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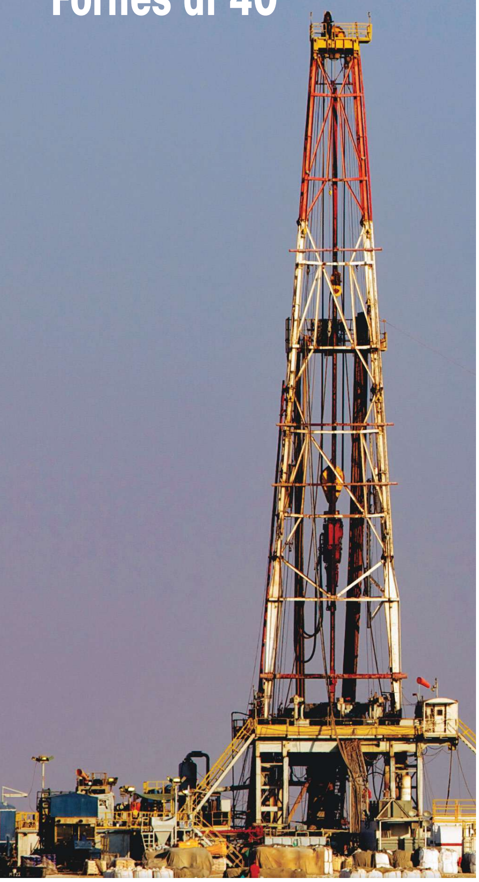

REGIONAL REPORT:
>> *Middle East*

STEPPING IT UP

Striking the Balance Between Innovation and Economic Reality

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE
A HART ENERGY PUBLICATION
DECEMBER 2015
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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The January 2016 issue of ***E&P*** will discuss issues surrounding cost control and project management. Other features focus on seismic processing and interpretation, HP/HT drilling, water management, and offshore accommodations, and regional reports will feature China and Alaska. As always, while you're waiting for your next copy of ***E&P***, remember to visit ***EPMag.com*** for the latest news, industry updates and unique industry analysis.

ABOUT THE COVER A BP worker descends the LR5 rig at its operations in Oman. The field is the subject of a major EOR project. Left, BP will drill horizontal wells and use hydraulic fracturing to stimulate production from the tight gas reservoir. *(Images courtesy of BP; cover design by Melissa Ritchie)*

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PREMIUM CONTENT

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Shell makes hydrocarbon discovery in Browse Basin

Shell Oil reported a hydrocarbon discovery in the Browse Basin-Ashmore Cartier area of the Timor Sea. The #1-West Auriga is in the AC/RL9 permit area near Crux Field area and was drilled to 3,960 m (12,992 ft).

New oil discovery in Cambay Basin

Mercator Ltd. made a Cambay Basin oil discovery at offshore exploration well #2-Jyoti in India's CN-ONN-2005/9 Block (CB-9). The #2-Jyoti well was drilled to 2,806 m (9,206 ft). Multiple zones were perforated, and the discovery flowed 2,000 bbl/d of 41°API oil during testing on a 32/64-in. choke.

Edvard Grieg Field appraisal well encounters 66-m gross oil column

Lundin Petroleum AB completed appraisal well #16/1-23 S on the Edvard Grieg Field in the Norwegian North Sea. The discovery hit a 66-m (216-ft) gross oil column in pebbly sandstone with medium-to-good reservoir quality.

AVAILABLE ONLY ONLINE

Information sharing is key to cybersecurity

By Velda Addison, Senior Editor, Digital News Group

Recent attacks show that security threats are becoming more elaborate and should remain on the radar for oil and gas companies. A new center has been formed to help companies protect themselves.

Egypt, North Sea boost production for Apache

By Velda Addison, Senior Editor, Digital News Group

CEO said the company's international portfolio offers optionality, high return rates and immediate volumes. But North America remains the driver of future growth.

Applying technology in a downturn

By Rhonda Duey, Executive Editor

Better information helps operators make better decisions in a tough environment. Using prescriptive analytics can make the difference, said Daniel Mohan, senior vice president of marketing for Ayata.

Obama rejects Keystone XL, raises industry hackles

By Velda Addison, Darren Barbee and Emily Moser, Hart Energy

Since its initial application nearly seven years ago, Transcanada's Keystone XL pipeline has become a symbol for politicians and environmental groups—for different reasons.

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Evolve digitally or die

There's a lot more we can do before we call ourselves a truly smart industry.

The development and implementation of "smart" technologies has been underway for well over a decade in the upstream sector.

But it emerged as the commonest thread in opinions expressed by experts exclusively canvassed in this month's cover feature on what they see as the technology solutions that represent the best potential for overcoming the challenges facing the E&P sector today.

The digital oilfield and intelligent energy solutions are now part of our day-to-day business. But although it's increasingly being applied throughout the value chain, several of the experts *E&P* polled—and others *E&P* quotes from relevant studies also recently released—feel the industry has barely scratched the surface in terms of what can be done.

BP's head of upstream technology, Ahmed Hashmi, refers to digitization as an "emerging field" that can safely reduce costs and help achieve maximum performance. But he stresses that we need to look beyond our own business to learn about and put in place systems that can better tell us what is going on downhole and in the reservoir.

Chris Rittler, CEO of ABB Wireless, flags up the overall lack of modern network connectivity in the field. Leading players have begun to treat data as company assets, he said, adding that if companies are truly planning to do more with less by using timely data to operate and reduce downtime, the infrastructure that delivers access to those data become even more valuable and need to be up to the job if operators are to achieve "leaner, meaner upstream operations."

Better use of Big Data to achieve improved efficiency and performance is a challenge also highlighted by Dr. Chris Freeman, director of field development at io Oil & Gas Consulting. Despite capturing more data, the ability of most companies to effectively implement learnings from it is less advanced, he said, and more needs to be done to build teams with the necessary skills to develop systems that can properly interrogate data.

Mark Linton, technology and innovation director at Wood Group Kenny, agreed. Focusing on better standardization and simplification of subsea production systems, he pointed out that "recently the amount of data has increased exponentially, and companies must further develop systems to provide robust analytic tools to make appropriate decisions."

These insights back up an illuminating figure in one survey by Lloyd's Register Energy, which revealed that 61% of its respondents agreed that their ability to collect and analyze data will be critical to the overall performance of the business over the next two years.

Seems to me the writing is on the wall for all upstream companies—embrace the digital world fully or get left behind by your rivals in the evolutionary race while natural selection takes its course. E&P

Mobilizing thousands of people around the world poses unique and often location-specific challenges. GMS mitigates these challenges by ensuring a safe and efficient relocation process. (Source: Air Energi)

Global personnel mobility challenges solved

Meeting the demands of a global mobile workforce requires a little creativity and patience.

Graeme Lewis, Air Energi

Oil and gas projects are becoming increasingly resource-intensive and operate on an unforgiving schedule, where delays cost millions of dollars. Mobilizing thousands of people around the world poses unique and often location-specific challenges. Global mobility services (GMS) mitigate these challenges by ensuring a safe and efficient relocation process.

Air Energi's dedicated global mobility team (GMT) delivers GMS via 35 offices in 40 countries worldwide. The GMT is made up of highly trained professionals in the oil and gas sector and has in-depth knowledge of how the industry functions. This ensures a total personnel solution delivered by people who understand the situation and needs of both clients and candidates.

Global mobility is now an essential element in ensuring project success. Each case requires an individual approach to address any cultural, logistical or personal challenges that mobilized personnel encounter when on assignment.

Challenge—war zone illness

A cost engineer in Basra, Iraq, was submitted to an SOS clinic in 2013. Due to the severity of the engineer's condition, he required immediate medical treatment. As the camp facilities were not sufficient to treat him, staff requested that he be medically evacuated to Dubai.

Contact was made by team to the engineer's medical insurer, who liaised with the medical staff at the Basra clinic. Both medical teams agreed that the engineer was stable enough to fly unaccompanied to Dubai the next day.

A business-class flight was booked to ensure he traveled in comfort, while a GMT representative and driver were arranged to meet him on arrival and transport him to the hospital, where he underwent surgery.

The company's GMT communicated updates on his condition to the engineer's medical insurer, the client and his family. When the engineer was discharged, a company driver and representative drove him to a local hotel, where he recovered. Ultimately, the consultant was declared fit for work after passing a medical examination and stayed in Dubai to complete the remainder of his rotation.

Challenge—turbulent regions

Papua New Guinea (PNG) is home to the Papuan Basin, one of the most explored and developed hydrocarbon plays in the region. However, despite the government's goodwill toward foreign workers, it remains a turbulent region; crime is widespread, basic amenities are dubious and contracting a life-threatening disease is a significant threat.

A $19 billion LNG project is currently underway with 6.6 MM tonnes expected to be exported each year. The project requires a worldwide contingent workforce of 250 personnel to be assigned at any one time in addition to 9,000 locals.

The operator tasked the GMT with providing support for personnel needing to enter and exit the country safely and compliantly.

PNG immigration and labor legislation is complex, with the application process for a working resident employment entry permit and visa requiring 10 forms. In addition, medical documentation is required, including a full medical

Global mobility is now an essential element in ensuring project success. Each case requires an individual approach to address any cultural, logistical or personal challenges that mobilized personnel encounter when on assignment. (Source: Air Energi)

examination, HIV testing and a chest X-ray.

The GMT took responsibility for arranging all paperwork to ensure that mobilized personnel were compliant with legal, fiscal and immigration regulations. Compliance to local legislation and client policy is critical when moving personnel around the world. Air Energi developed an efficient and wholly compliant mobilization process, with every consultant arriving ready to commence work immediately. The GMT successfully obtained more than 1,000 PNG work permits and visas for more than 30 different client organizations, all within challenging time frames.

Given that the operator did not have a local presence in PNG, the GMT set up an office in the country's capital of Port Moresby. Otherwise it would have been extremely difficult to mobilize the vast number of personnel and provide the necessary support.

Each year the operator completes an audit of its suppliers, randomly selecting contracted personnel to ensure they are compliant to its processes, and Air Energi is the only tier-one supplier to have maintained 100% compliance.

The GMT's immigration practices also were recognized with the Good Corporate Citizen Award. Issued by the Department of Labour and Industrial Relations, the award recognized Air Energi for its commitment to employing and training Papua New Guineans as well as compliance with labor and immigration laws. This also means the GMT can apply for priority five-year work permits rather than the standard limit of three years.

Challenge—multiple locations

Air Energi's GMT was contracted to supply all personnel and associated mobilization services to support a $3.5 billion expansion project in the Central North Sea. The project called for coordination of multinational consultants across seven locations in five countries.

The global scope of the development meant that projects were running simultaneously in Italy, Spain and Dubai. Processes for work permits, visas and tax compliance had to be established and synchronized globally for successful project delivery.

Due to multiple project locations, strict compliance in the host countries was critical to ensuring the competency of personnel and to avoid delays. Essential areas included immigration paperwork, medicals and appropriate qualifications.

Recruitment commenced three weeks after the company was awarded the contract, meaning the GMT had a short time frame to organize the mobilization of hundreds of personnel around the world.

To ensure successful mobilization, the company appointed a dedicated account manager to work with the operator's leadership team. In keeping with local content regulations, 30% of staff at the sites in Italy and Spain were sourced locally, while in Dubai staff were mobilized from Singapore and the Philippines.

The company mobilized 426 consultants for the client and delivered the full support service required for successful completion of the development. The project came online as scheduled, with its timely success driven in part by the performance of GMS.

Set procedures and policies delivered by the GMT meant that the standard of service received by project personnel was the same in every location.

At the Cadiz site in Spain, a high volume of technicians were mobilized in a short time frame. The company managed all project logistics for personnel, negotiating accommodation, booking and coordinating all rotational flights and twice-daily buses to transport personnel from the hotel to the site and recruiting a bilingual U.K. expatriate as an onsite coordinator to address any language barriers.

Collaboration with the client was also necessary to make arrangements for those personnel without mandatory qualifications and certifications to be compliant. For example, when appointing consultants for the offshore hookup of the new platforms in the North Sea, 30% of candidates had no prior offshore experience and so had to be trained and certified prior to deployment.

All consultants were compliant with legal, fiscal and immigration legislation, and each individual experienced a seamless entry and exit from the region.

The model of appointing personnel to oil and gas projects is evolving. By approaching global mobility from a strategic perspective, the company's GMT recognizes, anticipates and mitigates challenges while identifying the right services, needs and realistic costs that together are critical for successful completion of a project. E&P

The wild frontier

A resource assessment over Newfoundland and Labrador has turned up some potentially remarkable numbers.

Rhonda Duey, Executive Editor

Anyone who says there are no more giant oil fields waiting to be found hasn't reckoned with Newfoundland and Labrador. This wildly underexplored region has had numerous technical and regulatory issues that have prevented widespread exploration. But a recently conducted integrated study, along with technological improvements and a revised regulatory regime, might change that scenario.

Richard Wright, manager of exploration, Nalcor Energy Oil and Gas

The resource assessment study, commissioned by Nalcor Energy to BeicipFranlab, indicates the potential for 12 Bbbl of oil and 3.2 Tcm (113 Tcf) of gas for just the 11 blocks that were offered in the 2015 licensing round. In a statement released Oct. 1, the Honorable Paul Davis, premier of Newfoundland and Labrador, said, "This is a momentous day for the future of Newfoundland and Labrador's oil and gas industry—we clearly know that there is more oil and gas waiting to be discovered and developed. Through this information, we know more about our resource potential than we ever have before. For the first time, detailed oil and gas resource numbers will be released in advance of a license round closing, providing a fair and level playing field for the global industry prior to bidding in the license rounds."

Already the region is known for some major discoveries. Statoil, for instance, with Husky as a 35% partner, has discovered Bay du Nord, with an estimated 300 MMbbl to 600 MMbbl of recoverable oil; Mizzen, with 100 MMbbl to 200 MMbbl of recoverable oil; and Harpoon, which is currently under evaluation. Statoil also is drilling its Cupid prospect and was scheduled to spud its Bay d'Espoir well on Sept. 13. The company is planning to finish drilling the well after the Nov. 12 bid round announcement.

In 2011 Nalcor embarked on an ambitious 2-D seismic survey with TGS and PGS and has now acquired a little more than 100,000 line km (60,000 line miles). The area extends from the tip of Labrador out to the Canada/Greenland border and south toward the Flemish Pass region. It's since been extended toward Nova Scotia. Controlled-source electromagnetics (CSEM) also is playing a role, and EMGS has acquired data over the area showing resistivity anomalies that align well with the seismic results.

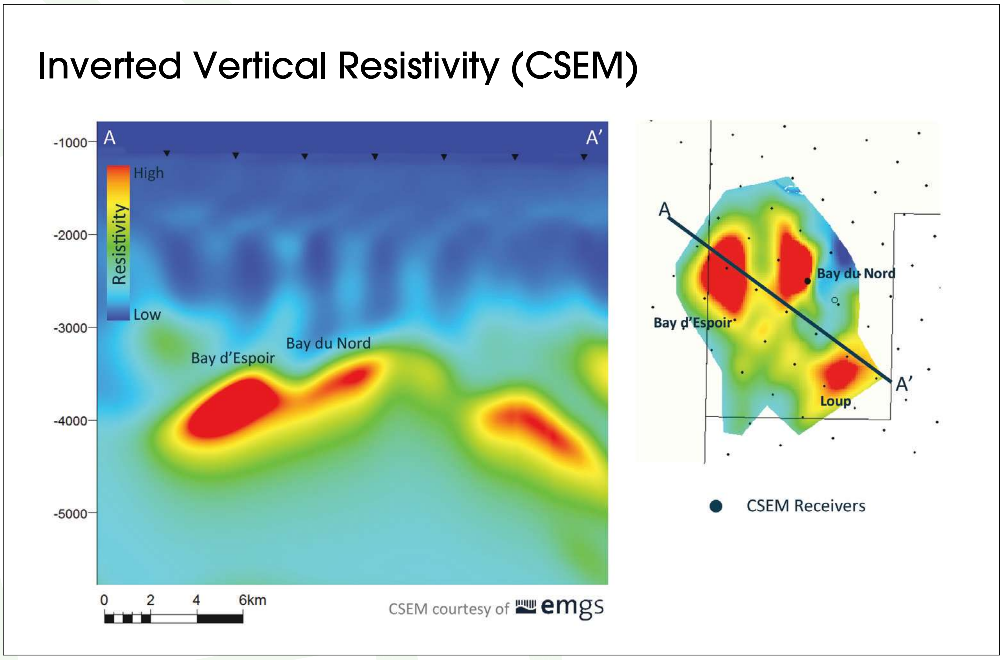
"A lot of these areas didn't have data on them previously to understand such basic questions as 'Where are the basins?'" said Richard Wright, manager of exploration for Nalcor Energy Oil and Gas. "If you think about the North Sea, these were questions that were answered in the late '60s and '70s. We're now getting to a lot of these areas. It's good because we've got some great technology to do it."

So where has this region been all of our lives? "If you look back to the '70s and early '80s, we were keeping pace in terms of data acquisition with Norway," Wright said. "In the early '80s when the oil price collapsed, a lot of investment came out of frontier areas like ours, and it took a long time to come back."

He outlined a few snags along the way. For one thing, the federal government of Canada was negotiating with the province over offshore rights. This was finally settled in 1985. Additionally, other legislation in Canada made it difficult to get seismic vessels into the area, and that wasn't settled until 2011.

"We've seen the amount of seismic activity increase appreciably over the last few years as a result of that," he said. "Last year saw the most 2-D seismic acquired since 1983."

Finally, the areas that are the subject of the recent study are slope and deepwater areas, which weren't a major focus in earlier decades because the technology hadn't yet matured to develop them. "It's early days for that, and there's a lot of area to look at," he said.



CSEM data over the license area shows prospective resistivity anomalies consistent with seismic data. (Source: EMGS)

Licensing

Wright said that the province had recently changed its licensing procedure, and the plan is to conduct additional resource assessment studies prior to each subsequent round. Areas with widespread activity will hold licensing rounds every two years, and frontier areas will be offered every four years.

"That allows us to gather data over the area subject to the licensing round and do resource assessments," he said. "It also allows oil and gas companies to plan their budgets and their people. They know that if they make investments in Newfoundland and Labrador in terms of people and budgets, there will be work to do for a very long time because of the size of the area." He added that each licensing round only covers 2% of the province's total offshore area—an area totaling 1.8 million sq km (695,000 sq miles).

The study

Wright said the methodology for the study was "unprecedented for offshore Newfoundland and Labrador." "We're taking the detailed seismic data and other data that have been acquired prior to the license round and using them in the final year prior to bid closing to do detailed resource assessments," he said. "BeicipFranlab created a 3-D basin model for the entire region."

This has been simulated through time, so explorers can take layers from the Jurassic and Cretaceous; bury them through time; and look at the thermal maturity, geochemical properties, total organic carbon, etc., to determine which areas are most favorable for oil and gas accumulations. Wright understands that some regions might have more prospectivity than others.

"Our goal is to make sure we have an objective understanding of what's in the offshore and do it in this piecewise way to get a highly deterministic answer," he said. "This is mapping from the leads and prospects up as opposed to making broad statistical estimates of how many fields may be in a large area. We're counting features from the seismic data."

And for explorers who are leery of the harsh conditions in the area, Nalcor has done an 80,000-page metocean study examining the area. It's in a map-based format and breaks the region into grids. There are 400 grids, and each has a 200-page report studying seven conditions in the offshore, including wind, waves, sea ice, current and icebergs.

"For every grid there's a quantitative ranking of how that grid cell, in terms of harshness or waves or wind, ranks against the Jeanne d'Arc Basin, where we've had production for 17 years; the Flemish Pass area, which is where we had the Statoil Bay du Nord discovery; and other areas like the North Sea, the Barents Sea, east and west Greenland, Sakhalin Island, the Caspian, all of those areas. Companies that are looking at the area have a quantitative piece of work that they can assess on a metocean perspective to assist the industry with making future exploration and development decisions, such as facility design for the area."

For companies that can stomach harsh environments, the prize is potentially huge. And Nalcor has done most of their homework for them. E&P

Pressure pumping primer

Well stimulation market stabilizes, but at low activity levels, as service providers await 2016.

Richard Mason, Chief Technical Director

It's the new theory of relativity. But instead of physics, this theory applies to well stimulation, where service providers are reporting a stable market—stable, in this instance, meaning relatively unchanged at low levels of activity.

Well stimulation service providers tell Hart Energy that pricing finally has hit bottom. Some providers are operating below cash cost, while all well stimulation firms are working below replacement cost. Pricing per stage ranges from the mid-$30,000s in parts of the Midcontinent up to the mid-$50,000s in select markets elsewhere. In general, pricing is below $50,000 on a per-stage basis vs. the mid-$80,000 range at the beginning of the year.

Well stimulation pricing moved down in two steps. The first was a reduction in charges for pressure pumping services, which characterized first-half 2015. The second step involved operators separating out bundled services and extracting concessions directly from vendors. Operators have become adept at negotiating price breaks for bulk commodity proppant and chemicals that were once provided through well stimulation firms. At this point, operators have successfully squeezed all the blood from the well stimulation turnip.

- **Roughly half of the onshore well stimulation fleet is stacked.**
- **Well stimulation pricing has bottomed.**
- **Operators pursue 'tried and true' completion recipes and forego experimentation in tough price environment.**

Hart Energy's market intelligence surveys indicate that roughly half of the industry pressure pumping capacity has been stacked. For the remaining units, variously estimated between 7 million and 9 million in hydraulic horsepower in aggregate, service providers report utilization in the low 60-percentile range.

Meanwhile, operators have settled on "tried and true" completion techniques. Few are open to experimenting in the current low-price environment. That means a completion recipe that generally entails slick water, plug and perf (PNP) and large proppant loading, often in excess of 200,000 lbs per stage. Those techniques are applied to longer wellbores, which exhibit more stages more closely packed together and feature anywhere from three to five perforation clusters per stage. Average stage spacing, based on survey reports, is about 68 m (225 ft) across the domestic horizontal market compared to 91 m (300 ft) a year ago and 152 m (500 ft) in dry gas plays four years ago.

Coiled tubing-conveyed fracture stimulation involving high stage counts and cemented sleeves has established a beachhead in the market. On a per stage basis, the cost is lower than standard PNP. However, the larger number of stages per well, in some cases nearing 60, means overall well cost is higher. Operators in some markets also are experimenting with dissolvable plugs.

The evolution in the downhole completion recipe indicates a subtle shift in industry philosophy. Originally, operators sought to bore the lateral as quickly as possible, then execute a massive frack to access the best rock. Reach was important. Now operators are intent on landing the lateral in the very best reservoir rock to start, even if it adds a day or two to drilling, and increasing the density of fracture initiation points closer to the wellbore. It's about quality, if quality is defined as complexity in near-wellbore fractures. The new completion technique is boosting initial potentials, whether measured over 30 days, 60 days or 90 days, and may well be increasing EUR as incremental gains in recovery factor are coming to tight oil just as they did to shale gas a decade ago.

How fast can the sector respond if demand returns? Well stimulation providers tell Hart Energy that the main bottleneck will be people. Thousands have been let go, many with experience, and inexperience on a pump job makes everyone nervous. The time to train and deploy new crews could stretch six months to a year after demand returns, although stimulation pricing will have started moving higher well before then. E&P

I, Robot

Automation has finally come to land seismic acquisition.

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Read more commentary at
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It had to happen.

With all of the myriad technological breakthroughs in seismic acquisition technology, one of the anachronisms has been the laying out of cables or nodes on land. It is a laborious process that requires considerable manpower. And with the constant demand for increased channel count, it has become a stumbling block to productivity.

"People are talking about 1 million channels per crew, and to have 1 million channels you have to be able to pick up and deploy 50,000 per day," said Richard Degner, president and CEO of Geophysical Technology Inc. (GTI). "You just can't do that by hand efficiently or cost-effectively."

Enter the Automator. It sounds like something out of an Arnold Schwarzenegger movie, but it's actually a simple but elegant solution to this problem. Designed by GTI and built by Sparx Engineering, the Automator plants nodal geophones robotically and eliminates the need for large land crews.

The Automator is designed to plant geophones robotically, saving time and money in land and transition zone seismic acquisition. (Source: GTI)

GTI is Degner's brainchild. He began forming the company after leaving the helm of Global Geophysical. The initial concept was to find a new type of nodal geophone for land and transition-zone acquisition.

"We found a design that we really liked, a concept with a form factor that lent itself to efficient operation," Degner said. "Within a year we purchased the underlying intellectual property behind it.

"We've spent the last two years developing that, testing the form factor and developing automation around it because we believe that nodal seismic recording systems need to lend themselves to automation to be highly effective and efficient."

The move to nodes already has enabled efficiencies, Degner said, doubling crew productivity while reducing costs by 10% to 15%. Adding the Automator will further drive this trend.

The device is fitted with six cartridges, each of which holds eight nodes. A self-leveling derrick within the machine adjusts for terrain to plant the nodes at true vertical. The unique design of the nodes ensures good coupling, which is important for reducing noise.

The nodes are fitted with a variety of positioning systems. GNSS and GPS provide location and accurate timing. They also contain a Bluetooth device to communicate with handheld Android tablets that then pass status and parameters by Wi-Fi to high-frequency radios or cellphones nearby to update their performance status into a master database.

While the Automator can't work everywhere, it can operate on a 16-degree grade, and Degner said it could handle 60% to 70% of the terrain in a region like the Marcellus Shale. The nodes can also be placed manually in more difficult terrain.

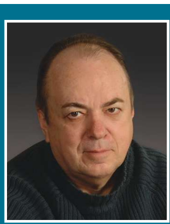
"I think automation is something that really is now enabled, especially with the form factor that we've created. And there's interest in robotics in general.

"Robotics to replace or enhance a doodlebugger was an eventuality that was certain to occur." E&P

Rhonda

IADC's Diamond Jubilee prepares contractors for next 75 years

Increased safety, reduced costs and enhanced efficiency are the key performance indicators for IADC as it readies for the next industry challenges.



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The International Association of Drilling Contractors (IADC) was meeting in San Antonio, Nov. 4-6 to celebrate its 75th anniversary. As the authoritative body for the drilling industry, the association set an overarching strategy of maintaining delivery of value to members during the downturn, preparing to rapidly increase delivery of value to members in the upturn and sustaining delivery of high value into the future.

"We've been going for 75 years. We certainly have a longer view in the sense that we know an upturn is coming. Our members are fighting to stay alive in the downturn. As IADC we know that in previous upturns this means spikes in incidents on rigs and the safety of returning crews. What can we do now for companies to ensure that they're going to have better crews coming back? We've got programs about new entrants and how to get them in the industry safely," said Stephen Colville, IADC president and CEO.

The 75th anniversary is a milestone the association should signify and celebrate. "However, we are on a continuum. The sun is going to come up tomorrow, and we'll still be drilling tomorrow. We have to carry on. Our industry is built on the shoulders of giants," he emphasized.

"We saw Kenny Baker and celebrated him for what he's done. He's a giant. You don't have to be a CEO for a corporation to be a giant. Somebody that makes a material difference is a giant," he continued.

Baker, drilling superintendent at Cactus Drilling Co., is the example of a giant that Colville mentioned. He was awarded the IADC Chairman's 75th Anniversary Award for individuals who have made a direct impact on improved performance for their company through a project or personal effort. The award is given every five years as part of the association's anniversary celebrations.

The BOP stack in the center of the photo leans to the left after the EF5 tornado struck the rig. The rotary table is on the top of the mud pit to the left of the BOP. All rig hands survived. (Source: Cactus Drilling)

As part of Baker's efforts, 42 employees are alive today because of his development of a tornado shelter as part of Cactus Drilling's equipment. He designed an anchoring system for the change shack on a rig that could withstand an EF5 tornado. Not only could this system save lives, it did—twice—and 42 people are alive because of it.

On May 24, 2011, two Cactus rigs were in the path of an EF5 tornado with 210-mph winds. Cactus Rig 117 took a direct hit. Because that anchored change shack was onsite, 12 men were saved to go home to their families. When they walked out of that shelter, what they saw was unbelievable damage. The rig was down. The 100,000-lb rotary table was on top of the mud pits. The BOP stack, as shown in the photo, was twisted out of shape. But the men were safe.

Now the anchored change shack is standard equipment on Cactus rigs, especially in tornado alley in Oklahoma. That's what IADC giants do. E&P

Scott


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Keeping the grit out

Filter, wiper combination works together to keep sand from fouling up rod pumps.

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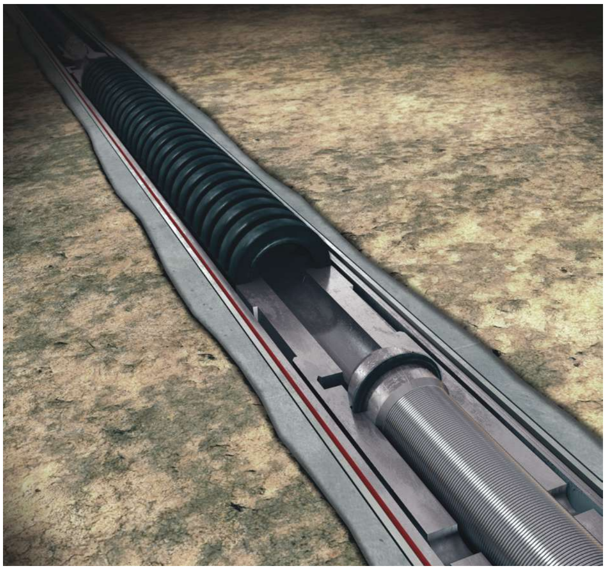
Impressive is the versatility of a single grain of sand. Through irritation, it can create and destroy. That single grain can become, in time, a pearl on the strand of your grandmother's favorite necklace. It also can be the grit in your grind when trying to enjoy an oyster dinner.

Its usefulness is demonstrated by propping open the pathways necessary for oil and gas to flow out of unconventional reservoirs. But it causes big problems in the nooks and crannies of the pumps used to create lift when reservoir pressures decrease.

From causing premature seal failures to the gradual scraping away of material, sand is an ever-present production nuisance. To help in the battle against premature wear and tear in rod pumps, Weatherford International released its new line of sand-tolerant pumps (STPs) in September.

Aimed to optimize the life of wells, the STP is an alternative to standard rod pumps in wells with high sand production in that it prevents abrasion caused by sand accumulation in the barrel/plunger. A wiper assembly and filter coupling reduce sand damage by moving sand upward through the pump and away from the barrel/plunger interface, according to a press release.



By using a wiper and filter coupling assembly, the STP helps reduce damage caused by sand to the barrel/plunger interface in reciprocating pumps. (Source: Weatherford)

The outside of the wiper assembly creates a barrier, keeping sand out of the plunger/barrel interface by continuously pushing the sand upward while the internal components of the assembly prevent sand from falling back into the plunger. The filter coupling enables only clean produced fluid to pass through the equalization ports to the plunger/barrel interface, a product brochure said.

The ports provide the necessary lubrication for the pump as the plunger moves up and down. The internal screen of the filter coupling prevents sand from escaping through the ports with the fluid. According to the brochure, the filters move with the plunger, with the fluid's sweeping action on the downstroke cleaning the filter and keeping sand suspended within the production fluid.

"The sand-tolerant pump is a demonstration of the improvements made in pump designs to increase runlife and mitigate sand damage. So far, the longest run time with the sand-tolerant pump is 781 days in very harsh sand-laden environments," Bob McDonald, vice president of reciprocating rod lift at Weatherford, said in a press release.

Available in most American Petroleum Institute pump sizes, the STP can perform in temperatures up to 182 C (360 F). Based on the results from field trials conducted in California, the STP has demonstrated up to 5.5 times longer runlife than conventional rod pumps in sandy conditions. E&P

Jennifer

Leaner and meaner

The oil price crash has put one-third of U.K. North Sea oil companies at risk, but despite this some are seeing signs of improvement.

JOHN SHEEHAN
International Editor
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Read more commentary at
EPmag.com

One-third of U.K. oil and gas companies are at risk of running out of working capital or even going bankrupt in the current oil price downturn, reports have suggested.

Companies have been taking evasive action to avoid this fate, slashing jobs and cutting costs.

Talisman Sinopec, which operates more oil fields in the U.K. North Sea than any other company, saw the writing was on the wall before the oil price crash.

The company operates 11 offshore platforms, an FPSO vessel and an onshore terminal at Flotta, in Orkney. It is also a partner in 46 oil fields.

Lauren McGregor, the company's functional excellence coordinator, told the recent Share Fair in Aberdeen that the business needed to change even before the oil price slumped by more than half.

Talisman Sinopec operates the *Bleo Holm* FPSO unit on the UK Continental Shelf. (Source: Bluewater)

"At the start of 2014 we started the transformation," McGregor said. "We started that before the price of oil fell. It was driven by the joint venture failing to meet production targets.

"We looked to reduce costs, and we have had a ruthless focus on performance and delivery. In spite of us reducing costs, HSE performance has improved."

She said the hard work has paid dividends. "We have a long way to go, but we have reduced opex by 24% and capex by 27%. As well as reducing opex and capex costs, we have increased production by 15%. We reduced our lifting costs by 34% in the period," she said.

Talisman Sinopec increased output as it brought its Claymore compression project onstream last year, while production increased from Tartan and the Godwin Field, which ties back to the Arbroath platform. These projects helped increase production by 15%.

"We had to make some really difficult decisions in the business, and we made a 25% headcount reduction. We have had to battle the falling oil price," McGregor said.

The 13 assets in the North Sea are all now responsible for their own performance, she said.

And the company was continuing to look for cost-effective engineering solutions that are fit for purpose, she added.

"In 2013 we might have been asking for the gold-plated standard, whereas in 2017 and beyond we might be asking for the bronze-plated standard. We are changing our model," McGregor said.

Other companies operating in the North Sea also are starting to see signs of improvement, and Nexen, a subsidiary of China's CNOOC, is increasing spending in the region as its Golden Eagle asset reaches the anniversary of its first year in production.

Richard Orr, a drilling and completions specialist with Nexen, told the Share Fair, "The picture isn't that negative from Nexen. The annual spend in 2016 is looking bigger than the previous two years."

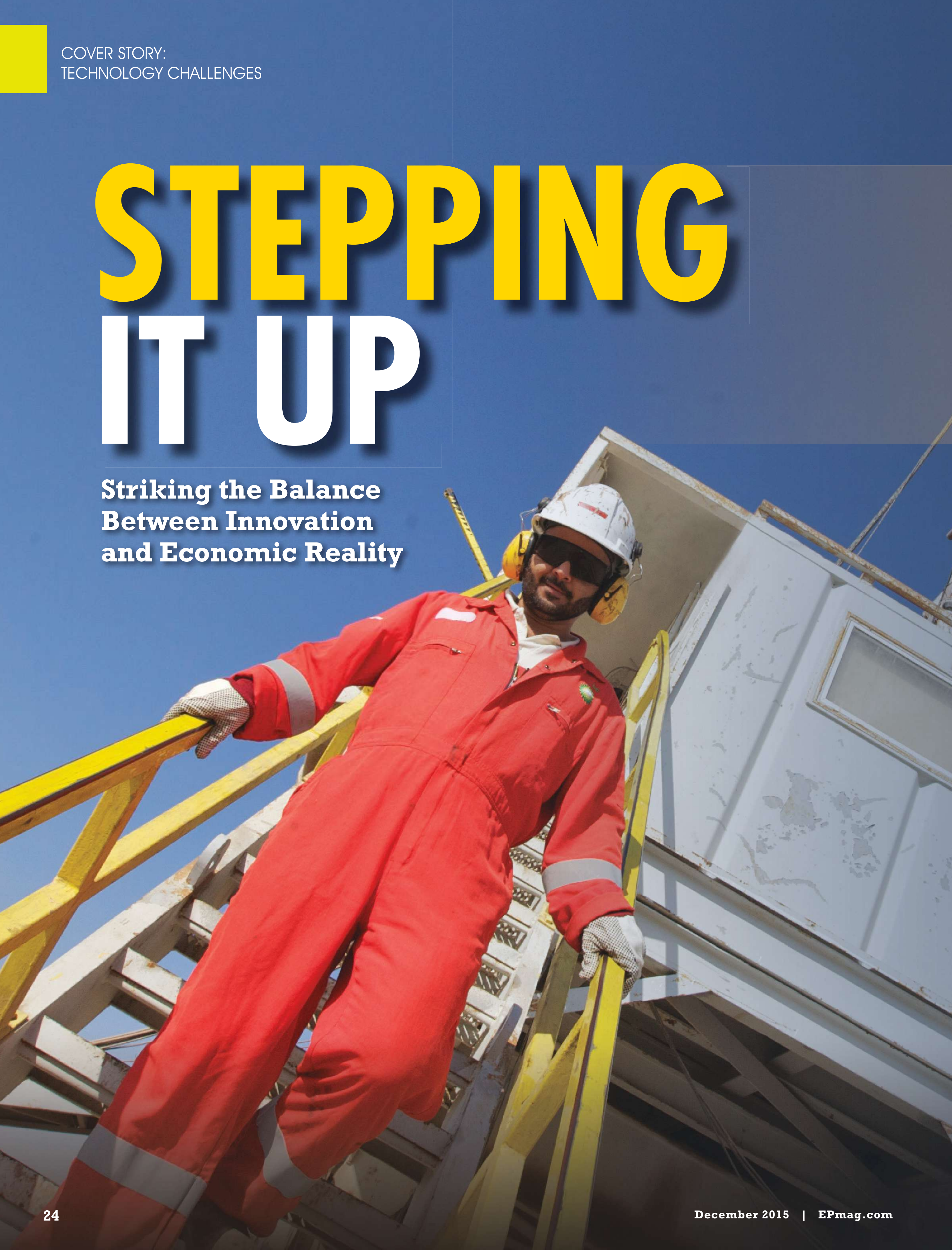
Nexen will be spending $590 million in 2016 compared to $452 million in 2015 and $557 million in 2014. "Every area of spend will be bigger than in 2015," Orr said.

Let's leave the last word to McGregor. "We are seeing the green shoots of recovery," she said. E&P

John

STEPPING IT UP

Striking the Balance Between Innovation and Economic Reality



Three of the upstream industry's primary goals in today's "lower for longer" oil price environment are to improve efficiency, eliminate waste and reduce cost—doing more with less. At the same time it must develop new and enhance existing technologies, which remain the most effective way to achieve this. But how does the E&P sector balance the need to invest its hard-earned cash in fresh innovation while also ensuring solid economic performance or even just survival?

This month's cover feature looks at global efforts to tackle this issue and asks a selection of industry experts for their take on what exactly are the two most important technology challenges and potential solutions out there. ■

BP is investing $6.8 billion on its Clair Ridge project west of the Shetland Islands, which will see the use of the first sanctioned large-scale offshore EOR scheme using the operator's reduced salinity water-injection technology (LoSal EOR) to carry out waterflooding. The field, seen here having its quarters and utilities topside modules installed earlier this year, is due onstream in late 2016. (Source: BP)

Walking the technology tightrope

You have to give to receive, or so the saying goes. For the upstream oil and gas industry, the difficulty lies in weighing how much to put into a project against how long a company is able to wait for a return—and what it will get out of it.

Mark Thomas, Editor-in-Chief

No one doubts that developing new technologies and techniques and improving on existing ones is the key to getting more oil and gas out of the ground.

But the damaging industry downturn continues to bite hard and deep. Analyst firm Rystad Energy's managing partner, Jarand Rystad, described it in the opening general session at the recent Society of Petroleum Engineers (SPE) Annual Technology Conference and Exhibition (ATCE) in Houston as the "biggest drop in investment ever, from $900 billion to $750 billion. This is not just cost-cutting. It could result in more than 4 Bboe in lost production over 10 years."

Concern is resultantly growing that in today's undeniable dog fight for survival that operators and service companies are in, they are being forced to cut too deeply into their investment programs for innovation. The paradox is that such technology solutions are often the very things that enable the industry to achieve what it needs—increased efficiency, maximized recovery, lower costs and higher profits.

Technology prize of 4.8 Tboe

Referring to the importance of such advances, a recent technology outlook by BP stated categorically that emerging and existing technologies could "significantly increase" the world's proven oil and gas reserves to nearly double the 2.5 Tboe forecast as needed to meet energy demand through 2050.

"Technologies such as enhanced oil recovery [EOR], advanced seismic imaging and digitization will have a huge impact on which of the available fossil resources we develop, how, where and when," stated the major's CEO Bob Dudley in the outlook.

BP believes proved reserves recovery from existing fields could increase from 2.9 Tboe to 4.8 Tboe through advanced EOR solutions, improved imaging, well construction and well intervention.

The proof is in the pudding. But it has been done before—proven oil reserves today are twice the level of 1980 thanks to a multitude of technological advances.

Improved technology and techniques such as hydraulic fracturing and horizontal drilling also have led to the dramatic production improvements that have come specifically from unconventional plays, BP said. In addition, companies have utilized pad drilling, added frack stages, extended laterals and used enhanced completions, all of which have contributed to further production growth.

Extraction costs 25% lower

BP's technology outlook also flagged the increasingly vital role of digital technologies in particular.

Increase production and manage inflow with real-time information and control in every zone.

With patented inductive coupler technology that provides power and telemetry, the Manara* production and reservoir management system can be deployed in conventional or extended-reach wells, in two or more sections, or across any number of lateral junctions—all with a single control line. Using the Manara system to monitor and control previously unattainable zones, operators can now immediately identify problematic areas, pinpoint the cause, and make the necessary adjustments to maintain the well at optimal production.

Find out more at
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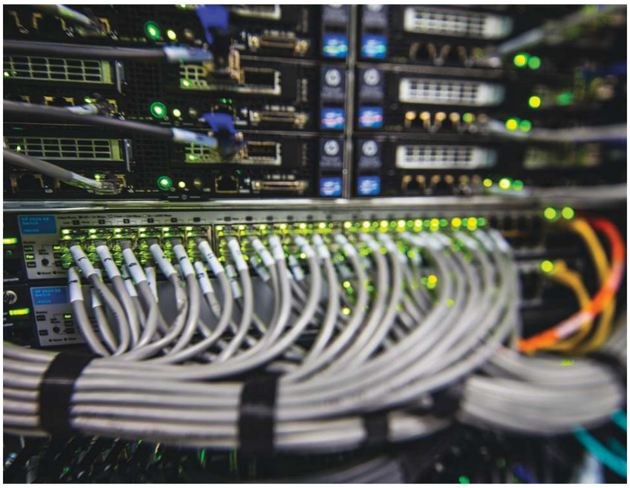
Schlumberger



Digital technology in action—the server room at BP's Center for High-performance Computing is pictured. BP said technologies such as advanced sensors, data analytics and processing, robotics and automation—all enabled and enhanced by supercomputing—have the most widespread potential to drive change, improve efficiency and make the industry more cost-effective. (Source: BP)

Advanced sensors, data analytics and processing, and robotics and automation, all enabled and enhanced by supercomputing, have the most widespread potential to drive change and make energy supply safer, more reliable, more efficient and more cost-effective. David Eyton, BP's group head of technology, stated in the outlook, "These technologies are already transforming the oil and gas industry, and the longer term possibilities are frankly difficult to imagine."

Such technology advances, said the company, could lower extraction costs by about 25% by 2050.

But in recognition of that constant balancing act between funding innovation and remaining competitive in a downturn, BP stated that producers "must commit to unwavering innovation through the oil and gas price cycles if they are to meet demand safely and at competitive cost through to 2050 and beyond."

Technology offers help on two fronts, the outlook continued. "The first is in raising short-term production, the denominator in the cost-per-barrel equation. The other involves attacking capital costs and operating expenses head on. Both place an emphasis on efficiency."

BP's admirable beating of the technology drum was echoed by a number of senior industry figures featured in another study released by Lloyd's Register. Its "Technology Radar 2015" report stressed the need for greater collaboration, data analysis and cultural change to address the innovation challenges in oil and gas.

Industry falling short

The Lloyd's Register's report reflected the general industry concern over how the current downturn is impacting technology development budgets—nearly half of the 450 senior upstream oil and gas executives interviewed admitted they had "fallen short of their innovation goals in 2015—a twofold increase since early 2014."

Alarmingly, 76% also said the recent price instability had led their firms to "slow or halt most of their innovation initiatives," according to the report.

However, it does appear to depend partly on how far out from completion certain technology initiatives are. SPE President Nathan Meehan said in the report that companies are concentrating on projects that have a good chance of succeeding in the near term. "They may be in material science or efficiency improvements, or displacement of other technologies. However, long-term disruptive innovation projects are going to take a back seat for now," he said.

Two-thirds of those interviewed also said they were under pressure to collaborate more with other organizations in the sector and to seek out more "crossover technologies" from other industries such as the aerospace, defense, IT, telecommunications and biomedical sectors.

Innovation's role

John Wishart, Lloyd's Register's group energy director, stated in the report, "The oil price slowdown is clearly impacting investment in innovation initiatives. However, our report finds that contrary to perceived wisdom, innovation has a crucial role to play in the current environment, where it creates operational efficiencies and is cost-effective."

He added, "Encouragingly, our findings show that overall the industry understands the need for innovation and has begun reaching out to other sectors to gain technological insight."

The role of data collection and analytics in driving innovation also was once again highlighted as a "must-have" factor, with a lack of data and systems integration across different parts of the business seen as huge barriers to successful data collection and analytics and with silos the biggest cause of the issue.

Digging into the depths of the Lloyd's study, Eyton pointed out that waterflood and gas-based EOR are among the innovation priorities because these specific EOR technologies are price-competitive. "They don't have the same kind of downside from a change in the

oil price that other technologies might. They're much lower cost to develop than, for example, thermal EOR technologies."

Digital technologies, he said, arguably offer the greatest efficiency benefits to be gained in a low-oil-price world. "They have the advantage of being scalable at comparatively low cost and can be deployed upstream more quickly than other technologies, which take years to scale from bench to pilot and to the field."

Encouragingly, Eyton confirmed that BP is investing more in the digital sector than in previous years.

Finding more reserves

Jonathan Carter, head of technology and innovation at operator E.ON E&P UK, said in the Lloyd's study that finding new reserves remains the top priority.

"Although there is a short-term focus on cost reduction, the longer term objective hasn't gone away. It's about maintaining and growing reserves. You've got to find new stuff, and you've got to do it better. If we have two years of a lower oil price, everyone will get used to it. The current urgency about cost reduction is merely a reaction to the rapid drop in the oil price," he said.

Tapping new reserves and reducing costs are not mutually exclusive objectives. Operators have opportunities to simplify even deepwater operations with a view to reducing cost and risk. The unnamed executive of one operator soon to launch a deepwater project in the southern hemisphere said in the report that it is refraining from putting too much advanced technology into its planned subsea system. This is to reduce risk and limit maintenance needs as maintenance accounts for a large chunk of subsea operating costs, he said.

Another oil major executive, also unidentified, added that he was certain that subsea trees will soon be entirely electric rather than today's conventional multiplex electrohydraulic design. The company can't afford to invest in fully electric trees for its deepwater sites at this time but is configuring a subsea system that starts with multiplex electrohydraulics and transitions to electric over time.

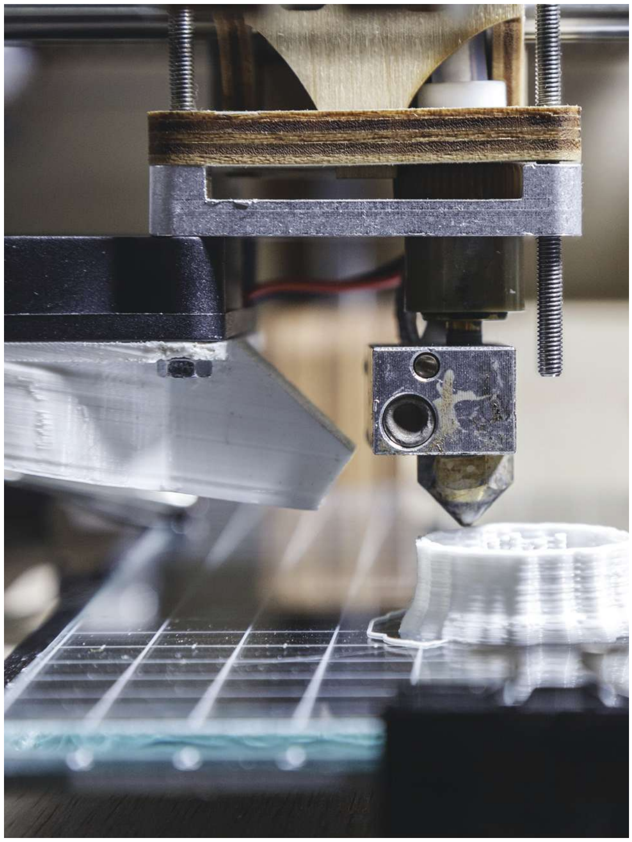
Petronas on technology path

One operator prepared to continue putting its money where its mouth is was Malaysian national oil company (NOC) Petronas.

Adif Zulkifli, senior vice president, corporate strategy and risk, was alongside Jarand Rystad in the SPE ATCE opening general session and stated that the NOC remained committed to investing in new technologies. "There are a couple of challenges that we face in particular. We are trying to focus on EOR—the challenge is more difficult today than it was before, but we will continue along the technology path and bring costs down.

"We also are focused on the challenge of carbon sequestration. Technology will continue to be invested in, and we will try to do this to make better efficiencies."

Rystad stressed that the current depressed market was in fact a "moment for opportunities for boardrooms and for governments. It needs some people to stand up and seize these opportunities." But, blaming a "herd mentality," he said he had seen "a lot of good research projects put on hold."



Additive manufacturing technology has the potential to vastly reduce supply chain costs.

3-D printing

Not everything is on hold, however.

Some specific technology areas were highlighted as potentially game-changing at the SPE event, including additive manufacturing, also known as 3-D printing. With the industry's focus on cost efficiency

and equipment delivery times, the ability to now get increasingly complex parts such as rotors and stators made locally in a region using 3-D printing techniques has plenty of attraction.

Rick Lucas, CTO at ExOne Co., outlined the applications to delegates during an R&D topical luncheon. Being able to get this type of part locally printed and distributed rather than manufactured and delivered via the traditional international supply chain with its long lead times, high transport costs and large carbon footprint could dramatically lower costs and delivery times, raising efficiency levels. "We will continue to see additive manufacturing making more and more sense," he said.

The subject is now the focus of a joint industry project (JIP) launched by Lloyd's Register Energy and additive specialist TWI. Global trends indicate the market is set to grow by 390% in the next seven years, according to Lloyd's. With additive manufacturing on the rise, it is set to have a potentially significant impact on the upstream sector. Sponsor participants in the JIP will be able to gain early adoption of approved additive manufacturing practices for their products, while longer term benefits could include reduced manufacturing and maintenance costs, faster lead times on complex components, component life extension, and increased durability.

Offshore wind power

Another JIP is tackling the industry challenge of increasing offshore power requirements, especially for remote locations. Wind power is viewed as a concept that could supply the answer. A DNV GL-led JIP called WIN WIN (WINd-powered Water Injection) has eight participants: Exxon Mobil, ENI Norge, Nexen Petroleum U.K. Ltd., Statoil, VNG, PG Flow Solutions and ORE Catapult.

According to DNV GL, initial studies show that a standalone WIN WIN system could be cost-competitive for various types of applications, particularly for water injection far from production platforms and when costly retrofitting is not an option.

With companies from both industries involved, the project is currently working to further develop to technical feasibility what is admittedly still very much a conceptual solution. Two of the main challenges being addressed are the off-grid operation of the system and the reservoir's response to variable injection rates.

The JIP is looking for other relevant applications of the concept as well as pushing to ensure it moves from the drawing board to a prototype and actual realization in a project. The project, which got underway in early 2015, is scheduled to complete its initial phase in first-quarter 2016.

Question of commerciality

Another challenge facing any technological innovation is not the innovation itself but judging its likely commerciality.

Partha Ganguly, senior manager (wellbore intervention) at Baker Hughes, told delegates during the SPE ATCE topical luncheon about how the company invests between 3% and 5% of its revenue on R&D.

One of the main questions during the development process for such a product, Ganguly said, is how to scale up production if it becomes commercially viable. Others include choosing which product has the most potential, testing it, measuring the value proposition and then deciding whether to "go or stop."

A key factor is, of course, return on investment (ROI). "ROI has to be between 10% and 15% of revenue from a product in year one and 30% of revenue from years one to five," he said. "R&D investment needs to manage both project costs and delivery risk."

He highlighted commercial success stories such as the company's innovative IN-Tallic disintegrating frack balls, with more than 90,000 deployed applications in multistage fracturing systems since 2011. Composed of controlled electrolytic metallic nanostructured material lighter than aluminum, it disintegrates when exposed to the appropriate fluid. The disintegration takes place through electrochemical reactions controlled by nanoscale coatings within the composite grain structure.

Timescale

Lucas stressed that a major challenge for new technologies is simply time pressure in terms of how long it may take for a technology to get accepted. "Sometimes it's a 3- or 4-year plan. You have to understand the customer and market very well. Some larger companies know it's going to take more time. Smaller companies may be looking for quicker returns," he said.

The pace of technology can be relentless, according to fellow panelist Richard Byrd of Lockheed Martin's oil and gas division. "The challenge is that you want these products developed quickly. It's a fact that some technologies developed now will be obsolete in just 18 months or less," he said. E&P

Rising to the challenge

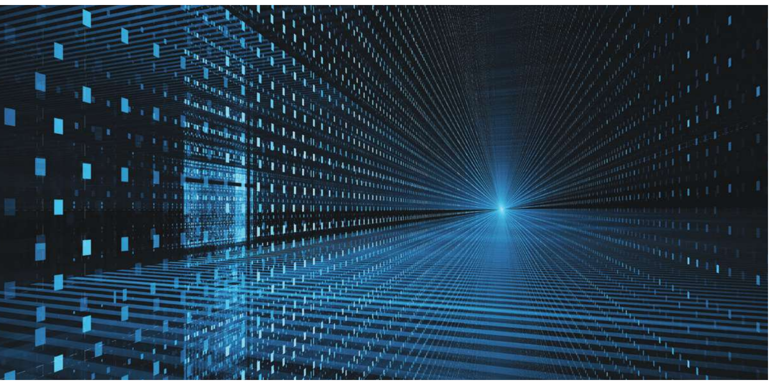
Industry experts evaluate potential solutions to difficulties facing the oil patch.

Staff Report

Despite tremendous strides in technological advances, the oil and gas industry is never without its challenges. *E&P* polled several technology gurus at oil and service companies to get the conversation rolling.

Ahmed Hashmi, head of upstream technology, BP

The two most pressing upstream technology challenges facing the energy industry today are both related to economics. The first technology challenge is safely reducing the cost of resource recovery. This is always important but never more so than in today's environment of low oil prices. The question is how do we get the maximum performance from today's technology, and the answer is that it can be done in different ways.



Digitization is an emerging field that can improve efficiency and safety and lower costs.

One way to reduce spending by way of technology is through digitalization. This emerging field can be a significant factor in improving efficiency and safety and ultimately lowering costs. As an industry, we should look beyond the oil and gas business to learn and put in place systems that can tell us what is really going on in the wellbore, near the wellbore and in the reservoir. The BP Well Advisor program is an excellent example of this in action.

Digital technologies have always collected data points relating to pressures, depths, direction and other variables. But until recently there was no technology that could turn that raw data into information for use in real time. BP Well Advisor technology enables operators to integrate those real-time data with predictive tools that are converted into easily understood graphics and displayed on computer consoles.

Another challenge for the future is to become more efficient and effective through the use of technology enhancements such as drilling automation, low-cost artificial lift, and water treatment and reuse. Effectiveness means getting more production per well by safely targeting reservoir segments of good deliverability and designing highly productive completions. This requires integration of multiple sciences such as geology, geophysics, geomechanics, petrophysics and chemistry.

Doug Valleau, chief geologist, Hess Corp.

It's become a common refrain for companies with unconventional E&P operations to say they need to find ways to work cheaper, smarter, safer and more efficiently to be competitive, especially during the current low-price environment. This is part of the DNA at Hess, where the culture is driven by principles of lean manufacturing. This is key to our expertise in unconventionals and long history in EOR. A primary goal is to increase efficiency and eliminate waste. Technology is an effective way to achieve that. One of the biggest challenges Hess faces, particularly during times of low crude prices, is to remember the importance of technology and innovation when we are exploring ways to become more efficient. By driving value with an emphasis on technological solutions, Hess has been able to make several decisions that have increased efficiency. In turn, we can do more with less. For example, Hess recently partnered with GTUIT and is operating 15 wellsite gas capture and NGL extraction units in the Bakken. With a small investment, Hess has been able to process an additional 8,014 cu. m/d (283,000 cf/d) of associated gas while reducing flaring.

While Hess has some of the best acreage in the core of the Bakken, the company is always looking for ways to squeeze more oil out of the rock. Looking forward, precisely what technology will be needed to coax more oil is still unclear. So Hess has invested $25 million in the Hess Digital Rock Physics Laboratory at the University of Wyoming. The facility is the only laboratory in the world that can study three-phase fluid flow through ultratight rock at the macro, micro and nano scale at full reservoir temperature, pressure and stress conditions.

Hess can recreate underground flow at temperature and pressure conditions, real things that are encountered underground in real reservoirs. For example, Hess is conducting reservoir condition three-phase micro corefloods in liquid-rich ultratight rock to directly observe the impact of custom surfactants on recovery efficiency. The bottom line is that through the appropriate application of advanced technology using lean processes, Hess is increasing recoverable reserves, becoming more capital efficient and doing so in a way that fosters environmental stewardship.

Chris Rittler, CEO, ABB Wireless

The most pressing technology issue is the overall lack of modern network connectivity in the field, which includes both devices and personnel. Modern networks include broadband and narrowband wireless technologies as part of a complete managed industrial wireless solution. If oil and gas executives want their operations teams to increase efficiency by implementing digital oil fields, the fabric that ties the digital oil field together—the network—cannot be overlooked.

Leading oil and gas players have begun to treat drilling and production data as company assets. If companies are truly planning to do more with less by using timely data to operate by exception and reduce downtime, the infrastructure that delivers access to that data becomes more valuable to the business.

From intelligent wellhead monitoring and control to asset tracking, mobile access and video surveillance, comprehensive wireless networking solutions that address every aspect from the operations center out to the sensor are critical to achieving higher operational efficiency.

Modern wireless systems support multiple oilfield applications by using an optimized mix of network technologies to create a flexible, scalable architecture. When used in combination, point-to-point and point-to-multipoint (PTP/PTMP) systems and broadband wireless mesh provide very high levels of performance and reliability. PTP/PTMP systems provide the high-speed backbone, and broadband mesh can distribute that capacity to the edge with the ability to route around points of failure. This translates to much higher levels of network availability, proven to be 99.99% in some fields. Narrowband PTP/PTMP systems have a critical role to play in challenging terrain, connecting remote endpoints and creating local site networks where wireless input/output is gaining traction over traditional cabled infrastructure.

With a strong communications foundation, the digital oil field enables real-time production data, secure mobile access and cost-saving collaboration across departments—all things critical for leaner, meaner upstream operations.

Richard Alabaster, vice president of surface technologies, FMC

The first issue is the need to substantially reduce the costs of the entire value chain from drilling through completion to producing the hydrocarbons. Great progress has been made over the past years, and this has accelerated in 2015, but more remains to be done to bring operators' returns to an acceptable level in the new commodity price environment and to make these gains sustainable.

The second issue is optimizing hydrocarbon recovery from both new and "browning" developments. The ability to reduce the time to first sale, to understand in real time the flow composition and dynamics and to be able to take better actions more rapidly and cost-effectively will be key to this.

There are now technology solutions that reduce cost by reducing equipment size, footprint and complexity in addition to increasing operational flexibility; reducing installation and operation time; reducing the number of people needed onsite; and reducing the rate of equipment "consumption" (wear and tear). For example, FMC's InLine DeSander significantly reduces erosion of flowback and production equipment; new designs substantially reduce rig and manpower time to install wellhead systems or increase the fatigue life and durability of frack pumps; and advanced separation technologies greatly reduce the size of production processing equipment, improve output quality and thereby reduce downstream costs.

Regarding hydrocarbon recovery, advanced flow-treatment technologies can be applied in completion operations to rapidly and cost-effectively bring early production to sale while still cleaning up the wells. Second, we can more quickly release completion and early-production equipment by deploying high-performance permanent facilities earlier. Here again, advanced compact inline flow processing technologies enable these facilities to be pre-engineered for optimal footprint, cost and overall field performance and to be standardized and prefabricated for rapid installation. In addition, such permanent facilities provide high operational flexibility (turn-down ratio) to handle substantial changes in flow characteristics. They also produce cleaner water output that can be reinjected for better reservoir recovery and lower remedial intervention or disposed of at significantly lower costs. Third, optimal operation of both of the above is facilitated by the judicious use of sensors and automated real-time analysis and interpretation of the data they provide. Finally, these same technologies can be used to retrofit older developments to enhance recovery with minimal footprint and cost impact.

Dr. Chris Freeman, director of field development, io Oil & Gas Consulting

The overarching challenge in the offshore industry is making projects viable in the low oil price environment. The industry knows that advancing technology will be the key to enhancing recovery of remaining reserves in this environment, but producing new tools, technologies and equipment and changing the industry's way of doing things can prove challenging.

The biggest technical challenge of the industry is to reduce the costs of its E&P and development activities. This includes better and cheaper seismic techniques, faster automated drilling through more compact and lighter equipment with reduced maintenance and new equipment for deep water and other challenging field development conditions such as HP/HT reservoirs. As exploration goes further afield, equipment will need to be robust enough to stand up to new environments, especially deeper water and Arctic conditions.

The second main challenge is using data to its full advantage. Big Data is being touted as one of the secrets to the future of oil and gas as it allows the uncovering of invisible patterns and connections by linking disparate datasets. As such, there is the potential for operators to find many efficiencies and maximize the performance of components throughout their operations. However, there are significant challenges that must be overcome before the future promised by Big Data is realized.


Automated drilling can help reduce operating costs.

Today many companies have vastly improved their capability to capture data. However, for most their ability to effectively process and implement learnings from these data are less advanced. This is a problem that can only be solved with investment, talent and expertise, and companies must build teams who have the necessary technical and analytical specialties to develop systems to properly interrogate data.

When looking to access and explore new reserves, there are a number of technological advances that can assist operators, some of which are being trialed or currently used in offshore projects.

Remote technology is useful once a platform has been erected, as wearable technology such as Google Glass allows crew members to receive guidance from onshore support centers without transporting them to the platform.

Unmanned vehicles have been used on the seabed for remote operations for years, but now the industry also is using drones or unmanned aerial vehicles to examine remote locations before sending crews there. This unmanned technology allows for quick access to new sites without the cost of sending a live crew.

The automation of drilling also offers significant improvements, from consistent quality and improved performance to dramatically improved safety. Automated drilling also removes the potential for human error, as machines are able to complete repetitive and arduous work without suffering a decline in output.

New technologies such as subsea separation and subsea compression also will make a big difference to reduce the requirement for large platforms and/or floating processing vessels. These subsea systems also require minimal maintenance, thus reducing future operating costs.

To realize some of the potential offered by improved technology and Big Data, the industry is embracing the concept of the Industrial Internet, combining machines and intelligent data to provide analysis and predictive data that enable preventative maintenance. Simply put, a pipeline will be able to report on when it would have the potential to rupture months before an incident would take place, and equipment will schedule its own maintenance when it is needed.

Big Data also can be used for sophisticated reservoir monitoring, allowing companies to optimize field depletion planning and maximize return on investment. As more cloud-based systems come online, management tools and remote working practices will become more commonplace, leading to safety improvements and cost reductions.

Mark Linton, technology and innovation director, Wood Group Kenny

Today's challenges include subsea system design and operability in remote areas with increasing field and reservoir complexity. Accessibility to existing offshore infrastructure may not be economically or technologically feasible, so the industry is challenged to further develop subsea production solutions. Equipment reliability is a concern due to limited accessibility once installed subsea, and further equipment design and rigorous qualification processes are still being implemented to meet future demands.

Subsea production systems comprise myriad elements designed, manufactured, tested and installed by independent vendors and suppliers. Gathering and analyzing data such that the owner is able to operate and maintain the subsea production system as a holistic model is a complex requirement. In recent years the amount of data has increased exponentially, and companies must further develop systems to provide robust analytic tools to make appropriate decisions.

Data analytics continues to be an important challenge for all operators. Most collect vast quantities of data over the life of an asset's operation; however, very few successfully mine that data for trends, risks and knowledge to improve the next generation of asset design and operation. Simplification and standardization can really only be achieved if a full understanding of the optimal operating and design regimes is analyzed and reviewed.

Having a valid integrity management system ensures the above can be achieved. Standardization should not be a cyclic initiative; it should be a process embedded within global business models and organizational structures on a long-term basis. Also, it is essential to achieve alignment to company and industry standards as well as suppliers' standards based on functional requirements. Simplification of the requirements will need assessment of the risks and value accordingly to understand and mitigate any areas of concern. There is substantial work going on to advance this, especially through joint-industry projects. E&P

Why aren't NOCs closing the technology gap with IOCs?

Different pressures create different drivers for NOCs.

Crispin Keanie, OTM Consulting

As global reserves become more challenging to exploit, it is not surprising that the importance of technology, reflected as R&D expenditure per barrels of oil equivalent produced, has increased with time. But perhaps more intriguing is the fact that by 2010 gross R&D investment of the industry's largest national oil companies (NOCs) exceeded that of the major international oil companies (IOCs) for the first time (Figure 1). This milestone is surely confirmation of the growing desire of NOCs to reduce reliance on the technologies provided by IOCs and service company partners.

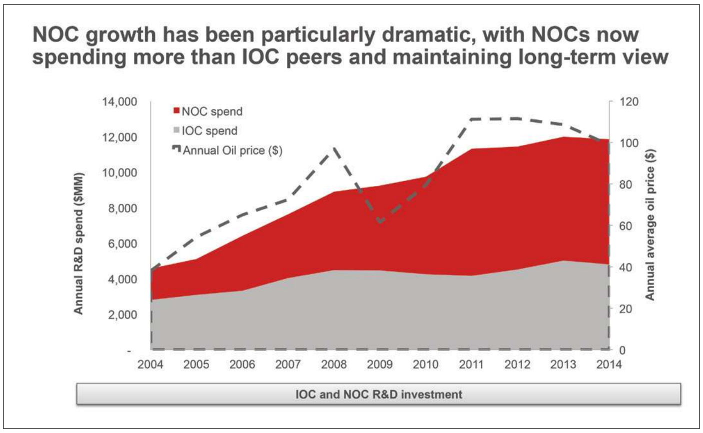


FIGURE 1. Gross R&D investment of the industry's largest NOCs exceeded that of the major IOCs for the first time in 2010. (Source: OTM Consulting)

But if this is the case, why are the major IOCs still renowned for technology excellence and why have NOCs, perhaps with the exception of a few notable examples in specific technology areas, failed to close the technology gap?

If R&D spends were being used effectively, should NOCs not be moving rapidly toward self-sufficiency and delivering a never-ending supply of world-first technologies via the application of systems and processes that have proved to be so successful for IOCs before them? Of course, the answer is not straightforward, and the reasoning for this lies in the perception of value.

As custodians of a nation's resource, NOCs find themselves in a unique position. They have the opportunity (many would argue a duty) to optimize production with the purpose of ensuring that maximum value is returned to the nation. However, this value extends beyond a fiscal metric and shareholder dividend as NOCs are tasked with a much greater objective. In addition to delivering their core business, NOCs also must stimulate the national economy; support industrial policy; drive forward education, health and welfare systems; and deliver prestige to the nation through demonstrations of technical excellence.

With such a responsibility, for an NOC (as it is for an IOC) the implementation of a structured technology management framework is vital to ensure that resources are used wisely. The most important ability is first to identify and prioritize operational challenges across the portfolio and to ascertain the options available to address them.

Challenges

The challenge triangle (Figure 2) is a method of segmenting the challenges faced by an operator (in this case an NOC) into categories that correspond to how these challenges may be addressed.

- Tier I corresponds to challenges that are unique to the operator or that cannot be addressed with existing technology across the entire industry. These require the operator to actively drive the pace of innovation, to invent solutions;
- Tier II corresponds to challenges that cannot be immediately satisfied by off-the-shelf technology. These challenges require some adaptation of technology to fully satisfy the operator's challenge within their specific application scenario; and
- Tier III corresponds to common challenges for which there exists an off-the-shelf solution.

Tiers I, II and III (the operating challenges) are experienced by all operators, IOCs and NOCs alike.

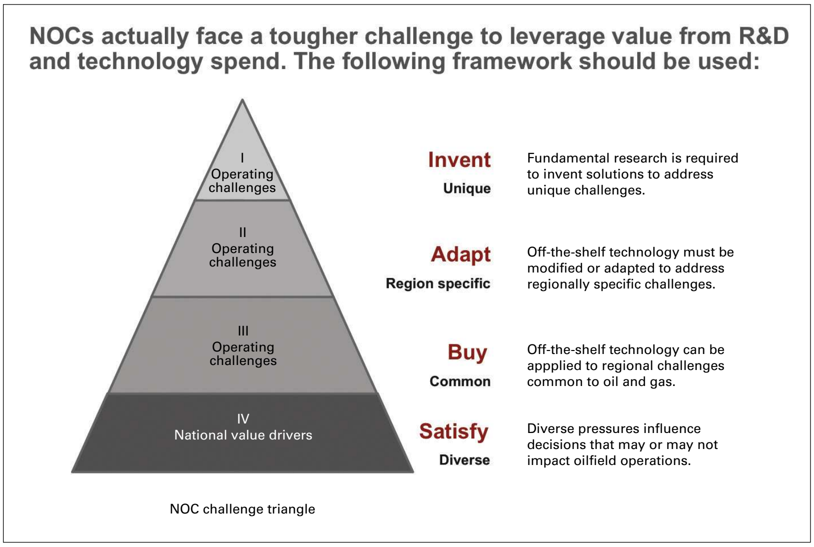


FIGURE 2. NOCs face different challenges than IOCs. (Source: OTM Consulting)

Tier IV

Tier IV, however, reflects the additional pressures placed upon NOCs that have little influence on IOC decision-making. These are challenges that exist within the nation outside of the day-to-day operation of the business that an NOC is obliged to address (i.e., national value drivers). For instance, these might include funding of research or education ventures (e.g., to increase annual Ph.D. outputs), the subsidising of infrastructure such as roads or hospitals and potentially even the seeding of other industries. Tier IV challenges compete equally, if not advantageously, for NOC resource and also might cause different decisions to be made in Tiers I, II and III.

The relative size of each tier will vary between operators by virtue of their asset base and strategic objectives, but typically speaking, in the order of 80% to 90% of operational challenges can be satisfied through adaptation or direct deployment of off-the-shelf solutions (Tier II and III). Despite this, there is a marked difference between the focus of R&D investment across the tiers between the major IOCs and NOCs. As was alluded to earlier, this is due to the way in which value is recognized.

Value quantification

For IOCs the quantification of value is arguably much simpler due to the fact that at its most basic level "value" can be crudely substituted for a fiscal (or sometimes an improvement in HSE) metric that quantifies the return on investment (ROI) once the technology has been deployed. Clearly, this is not strictly the case as factors such as staff retention, know-how and internal capability are all examples of intangible value returned from R&D even if the technology never reaches the field.

Nonetheless, IOC R&D efforts will focus on Tiers I and II with a view to delivering technology to the oil field in a timely and cost-effective manner ahead of or more effectively than their peers. After all, the objective of IOC R&D activity is to create a competitive advantage that enables continued access to reserves and, as a result, the satisfaction of shareholders.

For NOCs, with an additional layer of value factors to consider (Tier IV), the picture is more complex. These companies are influenced by pressures from their main stakeholder (the state) and tasked with developing national capabilities that can extend beyond the oil and gas sector. All of these factors must be considered and incorporated in the way that companies respond to their production-related challenges (Tiers I, II and III).

And given there will be very few areas where there is the justification to truly invent, NOCs tend to focus on Tiers II, III and IV where (arguably) the nation's greater value opportunity lies—in being a great adaptor and buyer of technology.

Being a great buyer of technology is no less important for an IOC but, less influenced by Tier IV challenges, it is less of a burden as expertise sourcing is far more mobile on the international market; buying capability can be acquired rather than grown. For NOCs, building and retaining this capability requires continued investment to train staff, and consequently to achieve the same level of buyer (and adaptor) capability, NOCs find that they must invest more intensely and over longer time frames than their IOC counterparts.

In conclusion, it is clear that despite being motivated by different drivers, technology and R&D investment is equally as important for NOCs as it is for IOCs. However, the value to be gained from this investment (the ROI) lies in a different place for each. NOCs do not need to invent technology at the same pace as IOCs because they are rarely competing for resource and, in fact, influenced by pressures from the state, their greatest value opportunity lies in developing great adaptor and buyer capability while investing in the long-term prosperity of the nation. Consequently, not only will the focus of R&D vary significantly between IOCs and NOCs, but so too will management processes and technology acquisition strategies. E&P

The BIG 4-0

The Forties Field came onstream in 1975 but shows no signs of slowing down just yet.

(Photo courtesy of Apache Corp.)

FORTIES *at* 40

When Queen Elizabeth II pushed a gold-plated button on Nov. 3, 1975, at BP's Dyce headquarters near Aberdeen, Scotland, to start production from the Forties Field, few foresaw just how long-lasting both she and the U.K.'s largest ever oil field would be.

Mark Thomas, Editor-in-Chief

Forty years later, Queen Elizabeth II has become Britain's longest-serving monarch, while the Forties Field has a different owner and is firmly established as the U.K. North Sea's longest-producing field, having achieved its official 40th anniversary.

The field is recognized globally as one of the world's historically greatest offshore projects. The past four decades have seen the development undertake an astonishing evolutionary journey from first oil up to the present day unrivaled by any other project in the world and will continue for many years to come, thanks to Apache Corp.

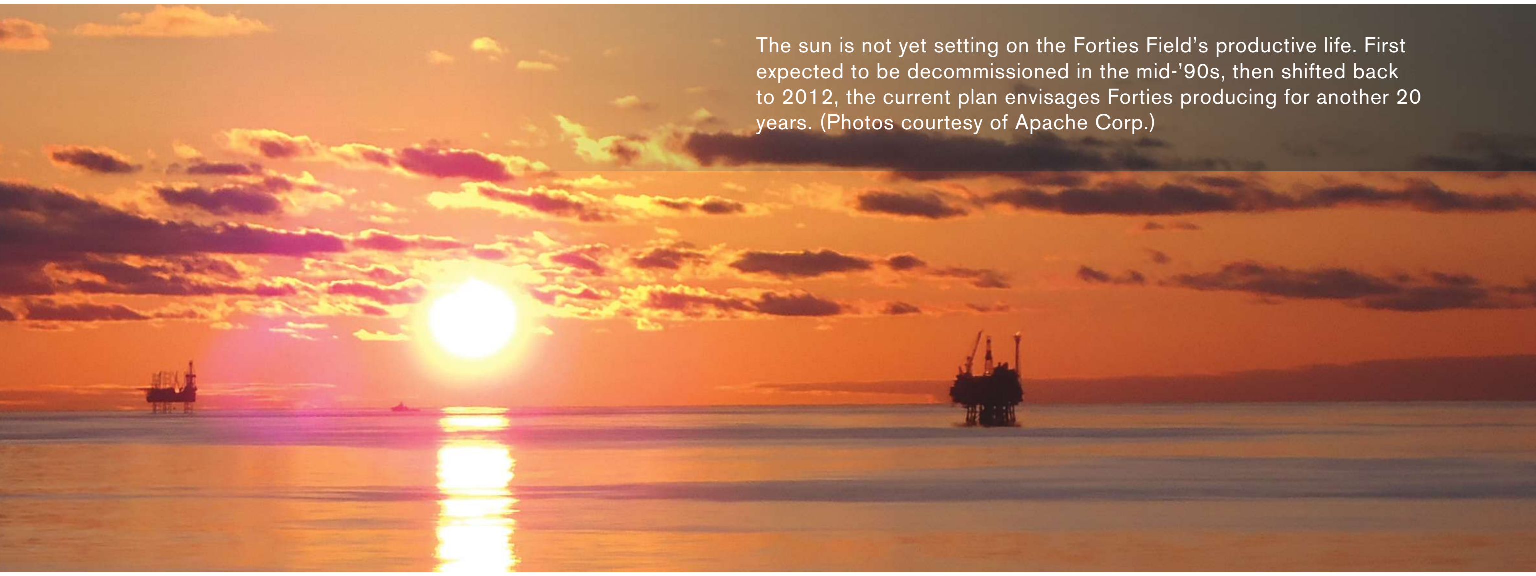
When the original operator BP chose to develop this giant field, first confirmed as a discovery back in October 1970 after being drilled by the semisubmersible *Sea Quest* rig, no one involved would have dreamed that it could still be producing in 2015, with plans potentially to take it well into the 2030s. But that is the current plan envisaged by Apache, which injected this declining giant with a whole new lease on life after taking over the reins from BP in 2003.

Culture is key

The industry-leading success of Apache's ownership and operatorship of the field since acquiring it from BP for $680 million is due to a whole gamut of reasons, including the company's bold leaders; its North American industry experience, operational know-how, technological innovation, teamwork approach; and its relationships with key contractors. But virtually all those involved today recognize that the key ingredient throughout has been a "can do" culture.

According to Apache's North Sea Projects Group Manager Mark Richardson, "Culture eats strategy for breakfast," quoting the renowned American management consultant and author, Peter Drucker. In this case, Apache's culture has eaten strategy for breakfast, lunch and possibly even dinner too.

Named after the sea area in which it lies, the story of the Forties Field itself is a well-known one to any oil industry professional. It essentially mirrors the birth and rapid growth of the U.K. North Sea itself and is as synonymous with the region as Shell's Brent Field (which was found the year after the Forties Field). The discovery of the Forties Field in Block 21/10 via well 21/10-1—which hit a 119-m (390-ft) column of good-quality oil—in October 1970 came only five years after the country's first-ever offshore discovery, also by BP, made at the West Sole gas field. It was also just 10 months after the U.K.'s first-ever oil find at Montrose, made by Amoco.


The sun is not yet setting on the Forties Field's productive life. First expected to be decommissioned in the mid-'90s, then shifted back to 2012, the current plan envisages Forties producing for another 20 years. (Photos courtesy of Apache Corp.)

When it began flowing oil to Scotland's Grangemouth refinery in 1975, it was just months after the first offshore oil in the U.K. Continental Shelf (UKCS) began flowing from the Hamilton Brothers' Argyll and Duncan fields in June that year.

World class

When the queen pushed the button that November day and formally began the flow of liquids (the field actually began producing two months earlier) through the 209-km (130-mile) pipeline stretching from Cruden Bay to Grangemouth, the inauguration signaled the successful completion of the crucial startup of the U.K.'s first world-class offshore development.

Initially featuring four large fixed steel platforms (a fifth was added in 1985) sited 177 km (110 miles) east of Aberdeen, the development had a total capacity of more than 100 wells and a production system that could handle up to 600,000 bbl/d. Following startup, the field's operational life saw exemplary industry standards set throughout its lifetime.

The field's original oil-in-place was put at 4.6 Bbbl of good quality 37° API gravity oil-in-place, with that figure now put at more than 5 Bbbl. When Apache—entering the North Sea for the very first time with the Forties acquisition—took over the operatorship, it was under no illusion that it was taking on anything less than a real-life industry icon.

Crown jewels

The field's revered status was proven by initial reaction to the sale when it was announced by BP on January 12, 2003, being likened by many industry observers as akin to selling off the crown jewels. But for both companies it made perfect sense.

BP wanted to strategically divest itself of certain mature assets that it considered economically marginal. This was at a time, of course, when the oil price was floating at about $12/bbl. The U.K. major wanted to concentrate on expanding its global upstream portfolio into new frontiers, a strategy that it implemented and achieved superbly under the bold leadership of Lord Browne—the former BP CEO who earlier in his career was an asset manager of the Forties Field.

In something of a premonition, the company stated at the time of the announcement that the Forties asset "may be worth more to others than to us," adding, "We believe this is an excellent deal for BP and Apache. Among other things, it brings to the UKCS a powerful U.S. independent for which Forties will be a highly material asset and therefore more likely to attract necessary future investment."

Perfect fit

They weren't kidding. For Apache, seeking to establish itself outside its core asset base in the U.S., it was a perfect fit.

Ironically, however, it was not the Forties Field that Apache initially had come over to discuss. The company had first cast its eye over BP's Montrose Field asset. After deciding that asset was not what it was looking for, Apache turned its attention to the Forties Field. Both sides quickly realized a deal could be done, and the initial agreement was in place in less than two weeks. Richardson recalled, "It was a very fast turnaround. I was actually on my honeymoon. I was on my way back and was sitting in Gatwick airport. I opened up the *Daily Telegraph* newspaper, and there was a picture of the Forties Charlie platform with the headline 'Forties sold to Apache.'"

BP agreed in principle to sell its 97.14% stake in the field (not including the Forties pipeline, which it still owns today), along with a package of other assets in the Gulf of Mexico, to Apache for $1.3 billion.

At the time, Forties was producing about 48,000 bbl/d, having reached a peak plateau between 1978 and 1981 of about 500,000 bbl/d, with that larger figure having been well above the early expectations for the reservoir. That peak figure at one point represented 25% of U.K. oil demand.

On the sale date an estimated total of 2.5 Bbbl of oil had been produced from the field, and BP estimated there were only 144 MMbbl of recoverable oil reserves left to be extracted.

Rejuvenated

Under Apache's stewardship since 2003, however, Forties' productivity has been transformed by a pioneering approach to the use of seismic and the drilling of wells.

The company's intense focus on identifying and acting quickly upon fresh opportunities to access new reserves and enhance recovery rates has resulted in Apache so far achieving total production of more than 235 MMbbl from the field, with 120 MMbbl coming from wells drilled into the Forties reservoir by Apache.

There also have been reserve additions of more than 20 MMbbl of oil from new satellite fields, and Apache believes there is the potential for another 100 MMbbl of oil to come. Every 1% increase in the field's recovery rate equates to about an extra 50 MMbbl of reserves.

It has become one of the best known examples in the global offshore industry of how to extract true value from a mature brownfield oil project. After the field was acquired Apache impressively managed to pay off the cost of the whole acquisition in less than three years.

Investment of $4.6 billion

Today, more than 20 years beyond the end of its original estimated lifetime, the venerable but reinvigorated Forties Field is expected to be producing well beyond the end of the next decade. All of this comes from a mature asset originally expected to be running dry by the early 1990s and which was penciled in prior to the sale for decommissioning by 2012.

Apache has invested close to $4.6 billion so far in the Forties Field, in virtually every facet of its infrastructure and what lies beneath. Key to the company's success has been intensive drilling activity, the carrying out of extensive facility upgrades and modifications, the installation in 2013 (38 years after it first came onstream) of a new platform linked to Forties Alpha, and a complete reevaluation of the reservoir through the use of modern seismic techniques. All delivered with an excellent safety record and a level of operational efficiency that is "best in class" for the U.K. North Sea.

The following pages detail the first part of the story of how one of the most pioneering projects from the golden era of giant North Sea fields has been transformed from a declining giant into a rejuvenated offshore powerhouse, which remains to this day a flagship in the vanguard of the U.K.'s latest generation of projects. ■

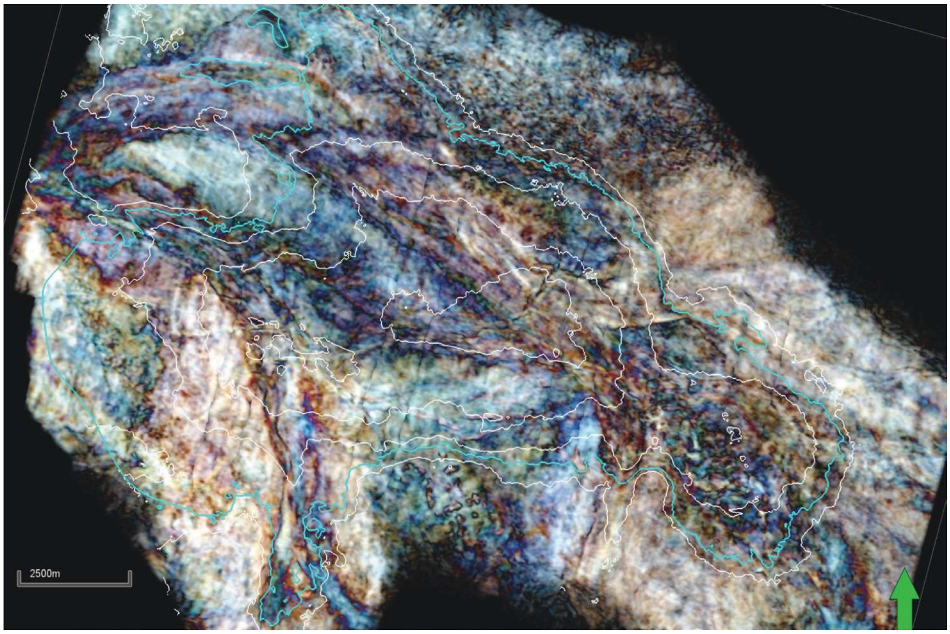
Editor's note: Part 2 of the Forties Field story will appear in January's E&P *issue.*

The giant steel jackets and topsides for the Forties Alpha and Bravo platforms were constructed by Laing Offshore at a disused ship repair yard at Graythorp near Hartlepool, England, while Forties Charlie and Delta were built by Highland Fabricators (HiFab) at Nigg Bay on the Cromarty Firth, Scotland. All four were installed and hooked up in 1974 and 1975. First oil flowed in September 1975.

Reawakening the SLUMBERING GIANT

Apache took over a world-famous mature giant of a field with declining production levels and gave it a whole new lease on life, making oilfield history in the process.

Rhonda Duey, Executive Editor



This spectral decomposition image shows the morphology of the channel systems. The Charlie Channel axis is clearly seen along with the thicker wing sands to the west. The thinner wings do not show up as well. Lineation within the channel belts also is visible, reflecting the stacking of individual channels. (Images courtesy of Apache Corp.)

One of the North Sea's truly original offshore pioneers, BP, had enormous success developing its huge Forties Field discovery. The project almost single-handedly established the U.K. operator's status as a world-class player for decades to come.

But by 2002, more than 30 years after that company-defining find was made, it was time to move on. The field, which came online in 1975, had been in steady decline for years.

A bold redevelopment scheme that would have kept the field producing well into the 2030s was put on hold because of various factors, including the fact that with an oil price at that time of around $12/bbl the project's economics were considered marginal. "If we'd done it, it would have been an enormous success," said Mark Richardson, North Sea projects group manager for Apache, who was working for BP at the time. "But at the time it didn't meet the metrics."

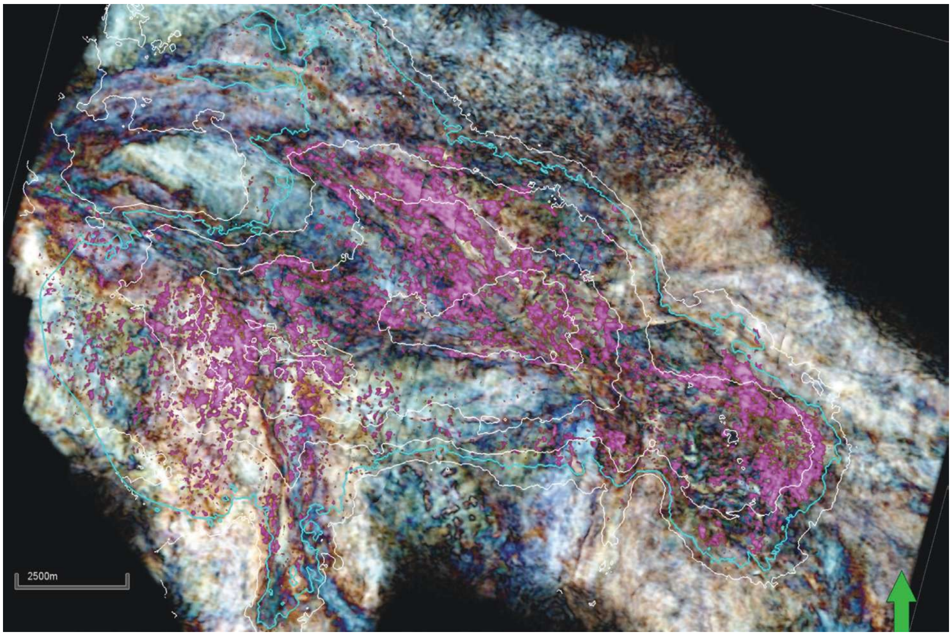
The field itself was discovered in 1970 when BP's 21/10-1 well was drilled into Paleocene sands to a total depth of about 2,135 m (7,000 ft). At the time the area was little explored, with only several smaller discoveries having been made, but the 1969 Ekofisk discovery offshore Norway renewed interest in the region.

The possibility that oil could be present was recognized as early as 1965, although the subsequent success exceeded all expectations.

A seismic grid shot in 1967 defined a structural nose extending southeast into Block 21/10 and indicated 40 sq km (16 sq miles) of closure in the block. The discovery well was drilled on this feature, with the probe producing 4,730 bbl/d on a $^{54}/_{64}$-in. choke. New seismic data were then acquired.

500,000 bbl/d

The appraisal well, 21/10-2, was spudded in 1971 a few miles northwest of the discovery well. It found an oil column of 33.5 m (110 ft), and a later appraisal well hit an oil column of 126 m (413 ft). At that point BP was developing plans for four platforms to develop the field.



Overlain on the spectral decomposition is the 1988-2000 sweep pattern. In the lower right-hand corner the sweep along the original oil-water contact is evident. This is in the area of the Echo platform that was brought online just before the 1998 baseline survey was acquired.

Once onstream, Forties was eventually averaging 500,000 bbl/d of oil through the early 1980s. In the late 1980s BP installed the Echo platform to do infill drilling, and later the operator also installed artificial lift systems.

But by the early 2000s it was clear that the field no longer fitted comfortably into the BP portfolio.

With almost immaculate timing, in 2003 Apache Corp. came searching for North Sea prospects. The company was originally interested in BP's Montrose Field asset but decided it was too small. Forties was offered up as an alternative option, and within two weeks the transaction was complete. "It was a very fast turnaround," Richardson said.

That was just the beginning of the story because Apache's success in revitalizing Forties has been nothing short of phenomenal.

Since taking control, it has drilled more than 160 targets at a 76% success rate. Apache purchased the field with 144 MMbbl of oil reserves on the books but has so far produced more than 235 MMbbl of oil from Forties, with 120 MMbbl coming from Apache-drilled wells.

Starting with an intensive drilling campaign on the Echo platform, Apache was able to boost the field rate from 45,000 bbl/d of oil in 2003 to 80,000 bbl/d of oil in 2005. The Forties platforms now produce more than 50,000 bbl/d on average. The three satellite fields Maule, Tonto and Bacchus currently contribute about 7,500 bbl/d of oil to the total. Infill drilling and satellite development have resulted in the establishment of a remarkable late-life production plateau for a field nearing the start of a fifth decade of production.

This success can't be attributed to any one technology, but it all starts with geophysics.

Urge to infill

Phil Rose, team lead for the Central North Sea at Apache, said the company bought the field because there were solid base reserves with a well-defined upside target portfolio. BP already had amassed a high-end geophysical database that included 4-D seismic and prestack lithology inversion, he said. Initially there was a strong target portfolio of 38 targets.

"I joined just after the purchase and remember my slightly skeptical interest when the chief geophysicist at the time told me how we were going to drill some 20 targets in the first year and that with time geophysical resolution would improve to reduce target size and greatly increase the number of opportunities," he said. "I could see six or seven but thought getting to 20 would be a struggle.

"However, as we started drilling in 2004, the experience of success soon made more opportunities apparent, and as they say, the rest is history."

Apache relies on an integrated multidisciplinary approach to continue to find new targets. Datasets include well log-derived attributes, seismic amplitudes, seismic geobodies and production information. These are integrated into the Petrel platform, which Rose said has been "invaluable" in combining these datasets. He added that it was clear from the start that continuing to acquire detailed reservoir geophysics would be the key to future opportunities. "Not only are 4-D data key to defining prospects, but every seismic inversion and imaging enhancement defines new places to drill," he said.

BP had acquired a baseline survey over the field in 1988 and followed up with two monitor surveys in 1996 and 2000. Apache continued the trend, acquiring three more monitor surveys in 2005, 2010 and 2013.

World-class

The main Forties Field is a Paleocene-aged turbidite channel sand complex trapped within a large four-way structural closure. Its stratigraphic complexity results in localized accumulations of bypassed pay. Its favorable rock properties make it a world-class example for the application of reservoir geophysics.

"It's not surprising that 4-D works, but it probably works beyond what you would ever imagine," Rose said.

Initial goals were to monitor the sweep patterns of the reservoir, which Rose said are never how he imagines them to be when the wells are drilled. "Therein lies the power of the technique," he said. These eye-opening datasets have led to numerous infill opportunities within the field. Eight years in, Apache had identified more than 100 targets with an overall success rate of 74%. This led to a return to surface drilling on the five platforms when sidetrack donor wells became scarce.

These seismic sections indicate small discontinuities present in the field derived from seismic coherency and spectral decomposition. They have been shown to be associated with sandbody edges as well as small faults. Often these discontinuities line up with the edge of a swept zone.

Lithology prediction also has evolved over the years. Apache's lithology prediction methodology uses amplitude vs. offset gradient associated with shale-to-sand interface reflections. The gradient response doesn't reflect the fluid content or acoustic impedance (AI) of the overlying shale. Gradient impedance (GI) and AI inversion volumes are created from the offset stacks and are cross-plotted. A lithology project angle is determined in this volume and is then used to generate a lithology prediction volume. According to Rose, the GI aspect is required to separate out the Forties shales from the sands.

Overall, new infill targets are defined by direct hydrocarbon indicators, 4-D seismic lack-of-sweep targets, development geoscience targets and simulation-derived targets.

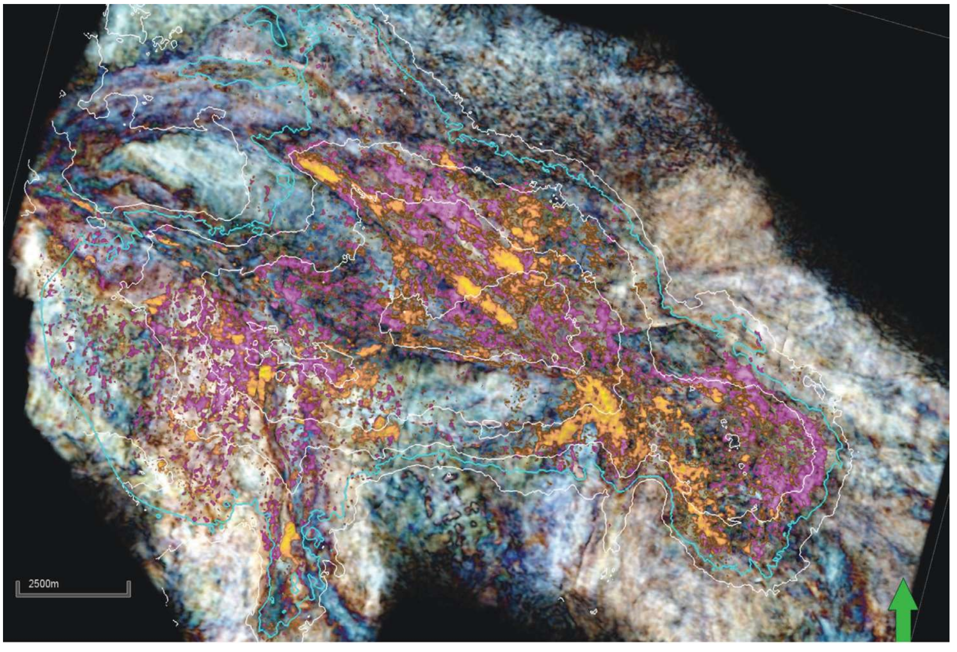
However, Rose said that Apache doesn't rely on simulation runs as much as other companies. "If you look around the North Sea, a lot of people are into reservoir development, which is very much engineering-led," he said. "It's difficult to get things justified without a reservoir simulation model.

"We've been drilling on seismic and actual observations. That's the great thing 4-D gives you—a real measure as to how things are draining. We do our best to push the data as far as we can, get the best data we can, and then allow ourselves to be guided by those data in terms of drilling. I think that's how we've managed to keep finding new opportunities."

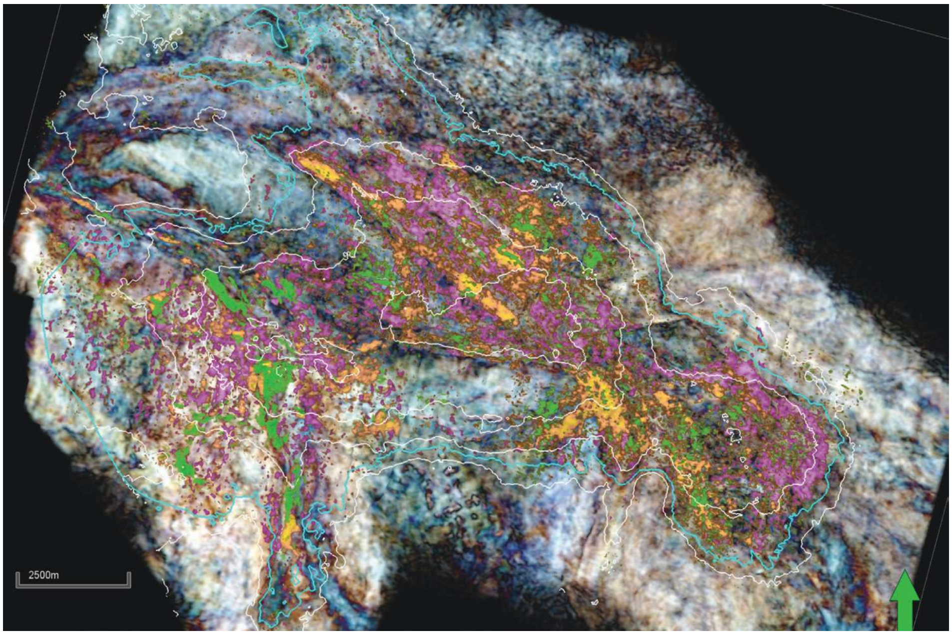
New data, new fields

Infill targets are not the only things being discovered at Forties—several satellite fields and near-field opportunities also have been discovered in the region. Satellite fields include Bacchus, discovered in 2005, Maule in 2010 and Tonto in 2013.

The Bacchus Field, in which Apache has a 50% working interest, currently produces 5,500 bbl/d of oil (gross). Gross cumulative production to date is 9.8 MMbbl of oil, and EUR is 18 MMbbl of oil. At a finding and development cost of \$33/boe, the field is economic even at low commodity prices. This



Sweep can be seen with associated sweep down by the contact due to high-rate wells drilled in the core of the Charlie Channel. The influence of the stratigraphy is evident in the Bravo/Alpha Channel. During the next period there was a focus on drilling wells in the Charlie Channel and infill drilling throughout the field.



Sweep response is filling in the holes with a strong response in the Charlie Channel. Apache is also seeing fluid movements on the western flank of Charlie. It has two successful wells in the area with plans to drill additional wells.

subsea development is tied back to the Forties Alpha platform.

Maule was drilled from the Forties Alpha platform and discovered a 14-m (46-ft) net oil column in Eocene-aged Brimmond sands. The company was able to develop the field under the U.K.'s small field allowance scheme, and it was brought onstream in less than nine months.

The field was identified on far-stack seismic data, which clearly showed the lateral extent and thickness of the reservoir. The field overlies the Forties, but earlier wells lacked the logs to indicate the presence of hydrocarbons. The field has produced 2.6 MMbbl of oil to date.

Tonto began production the same year it was discovered and currently produces from two wells drilled from the Forties Bravo platform. It too is under the small field allowance scheme. It has produced 1.1 MMbbl of oil to date.

Another discovery, the Aviat Field, is one that has been used to great effect by Apache. The gas field is being tied back to Forties Alpha not to produce its commercial gas but to provide a fuel source for the Forties complex. The development plan is a two-well subsea development.

A wild ride

For Rose, his time working on Forties has been a great deal of fun. "I can't believe it," he said. "The time has gone by very quickly, and it's been an amazing journey. I really didn't dream that I'd still be drilling Forties wells 12 years after I joined Apache. That was not my expectation at all."

Being able to continually acquire data has made a huge difference, he said. "I think there is a really clear connection in our experience," he said. "Every time we've improved our inversion techniques and gotten a high-definition lithology image, every time we shot a new 4-D survey, particularly as we've increased the definition of that survey and done things like removing time shifts in the data to clean things up or produced normal root mean square error pictures, these things have provided another way to evaluate whether a location is going to be a good or bad place to drill."

He added that Apache doesn't really have any "silver bullets" that other operators lack, but the geophysicists push the contractors to get the best data possible. During the last monitor survey that was shot, for instance, Apache personnel were closely involved with the contractor to make sure the survey had very high levels of repeatability, critical for a successful 4-D survey. "It's not so much that we're devising new algorithms," he said. "We're making sure we get the maximum value out of what's out there."

Both Richardson and Rose are quick to point out that the company's culture plays a key role in its success at Forties and elsewhere. "We don't have any special technical skills," Richardson said. "We don't have any special equipment or fields; we've got some of the oldest fields in the North Sea. Yet we still produce some of the highest standards of operational efficiency.

"The idea of not [taking risks] is total anathema to Apache, where it's all about delivery and turning things into action rather than discussing them."

Added Rose, "When asked the question, 'Are we going to drill the well,' it's 'yes' unless you can give me a really good reason why not to." ■

Technological Innovation Key to Enhancing Forties Field Drilling

From a wooden guide shoe to rotary steerable systems and gravel packing from a supply vessel, Apache has used a myriad of 'little pieces' of technology to revitalize the Forties Field.

Scott Weeden, Senior Editor, Drilling

Since Apache Corp. took over the Forties Field, the company has identified 302 targets and drilled 161, resulting in increased production and higher remaining reserves. And the drillers aren't done yet.

Three new satellites were developed in the field area—Bacchus, Maule and Tonto. The Maule and Tonto fields lie above the main Forties Formation and had not been targeted before. Tonto, which came onstream in 2013, was the third new oil field brought online by Apache in the Forties area since 2010, and its success was a direct result of the company's drilling philosophy.

"One of our strengths is that we will try out new ideas and approaches if they work for us, then fine, we'll continue. If they don't work, then we'll drop them and move on to the next thing," said Ted Hibbert, senior drilling advisor for Apache. "It's all about introducing these little pieces of new technology. We try to simplify things as much as possible while encouraging innovative thinking."

Apache started drilling operations with one crew on the Forties Charlie platform in 2003. Then in early 2004 things really got started when the jackup rig *Galaxy I* was put over the Forties Echo platform, followed by the *Galaxy III*. An aggressive redrilling campaign got underway that yielded immediate results.

The biggest challenge for Apache was based primarily on the age of the platforms and equipment. The integrity of the existing wells "was pretty good, BP had maintained them fairly well, which has been in our favor," Hibbert continued. Before drilling operations could really get underway on the four main field platforms, however, the rigs and equipment needed to be brought up to more modern standards.

Upgrading rigs, equipment

"None of the rigs had been used for more than 12 months. When we started off, we were basically starting all of the equipment from being idle," Hibbert added.

The Forties Echo platform originally had a small workover rig on skid beams. The drilling derrick, drill floor and beams were removed from the platform. The *Galaxy III* rig was jacked up next to the platform in early 2004 to start sidetracking wells. (Images courtesy of Apache Corp.)

An additional mud pump was added on three out of four platforms. Apache converted from the use of water-based mud to OBM for improved hole stability.

All of the derricks on the main field platforms were the originals. When BP left, water-based mud and kellys, mud pumps, drawworks and other equipment that had been there for many years was still being used.

One derrick on Forties Charlie, for example, was already more than 40 years old. Apache undertook a renovation program that saw all four derricks recertified, with activity taking place including completely rebolting them, replacing any cracked or corroded braces and recertifying them.

Apache got to work with further upgrades of the rigs. Very quickly it replaced the kellys with rented top drives. Iron roughnecks were fitted on the rig floors to improve safety and increase efficiency. "Over a period of time, we put top drives on all four installations, and the last installation to be converted to a top drive was actually the Forties Delta rig within two years," he continued.

On three of the four platforms, an additional 10P130 mud pump was added, which necessitated the removal of a cement silo, increasing the number of pumps to three.

Oil-based mud

A decision was made by Apache to convert from the use of water-based mud to oil-based mud (OBM) for improved hole stability. All equipment was converted to allow this, meaning the platforms had to be converted for full OBM containment to keep it from going overboard.

"One of the advantages of using OBM was with all the sloughing shales on Forties. OBM is very good at inhibiting those shales. It basically gave us the potential for drilling a better well—fewer hole problems, reduced pack-offs, fewer washouts and the ability to drill into the reservoir from the 13⅜-in. shoe at 1,000 m (3,280 ft) true vertical depth. We've drilled 161 targets and completed 131 wells, not to mention the number of workovers we have carried out," he said.

The shale shakers on the platforms were upgraded from VSM 100s to NOV/Thule VSM 300s. At the same time ergonomic changes were made by turning the shakers through 180 degrees to allow easier access due to a low roof at the cuttings trough end.

The mud pits were overhauled, and new grating was installed. "We're in the process of installing Palfinger pipehandling machines. We have two in operation so far on Bravo and Charlie. One of the issues in the winter months is that you actually can be shut down by the weather. If the cranes are down, we can now continue to operate using the Palfinger to transfer pipe or casing to the rig floor. It also allows drilling to operate independently of the platform crane operations.

"Another thing that we did to help us continue to operate through the winter months was to modify some of the original cement silos so we could use them for OBM storage as well. We increased our OBM storage, including base oil, from somewhere in the region of 1,200 bbl to about 1,900 bbl, not a lot for today's mobiles but significant for us," he noted.

"We've overhauled all the drawworks in the field, as well. You could say, over the period, we've probably stripped out just about every piece of equipment that we've got on the platform. These are all additional efficiency items to keep us working as long as we can during bad weather," he said.

People make real difference

Hibbert believes that a lot of the changes that Apache has been able to make have been due to the passion and drive of both the offshore drill crews and the onshore team. BP left a skeleton crew in place that went with Apache. From that crew Apache branched out and utilized its knowledge and experience on Forties.

Through a bid process Noble became the drilling contractor, and it was very much aligned with the way Apache does business. Noble subsequently sold off its platform drilling services to Seawell, which is now Archer (the current contractor), and many of the original Forties people transferred with them. One of the reasons for success is very much the drill crews.

"The guys that work offshore have a can-do attitude, and they're supported by a like-minded group onshore. If we do have a problem, people are very good at getting together, working out a solution and then going and executing the solution," Hibbert said.

A lot of the main field upgrades were instigated and managed in-house. The small in-house team also organized the engineering works, which elsewhere would have been left to the drilling contractor with all the associated overheads.

"Basically we organized all of that ourselves, and we got an individual contractor to do the work. That also has saved us a considerable amount of money, rather than giving it to somebody else as a project management activity. For every dollar we spent, we got a dollar's worth of work in reality," he said.

Reservoir cuttings injection

Another new technology included in the drilling campaigns involves reinjecting cuttings. In the North Sea operators cannot dump OBM cuttings overboard.

"I'm not aware that there's anybody else in the North Sea that injects their cuttings into the producing reservoir. I think everybody else is basically injecting cuttings down a separate annulus into a shallower zone. Injecting shallower for us could have created wellbore instability where we would have wanted to sidetrack at a later date. Instead by injecting those cuttings into the producing reservoir, we have avoided instability issues," Hibbert explained.

The cuttings are ground up and mixed with water in a slurry, which is then pumped into the produced water-reinjection (PWRI) stream at the christmas tree and down the water-injection tubing into the formation. That has worked very effectively for the company. Modifications were made to the BOP deck so the cutting reinjection slurrification skid could be installed and the existing portable cement unit used to inject the slurry into the PWRI stream.

"What you do need to do is make sure you overflush the injection well if PWRI is turned off. You need to make sure that the slurry has gone down the wellbore and quite a way into the formation before stopping injection. We haven't seen it as a problem so far," he said.

Pilot-hole drilling

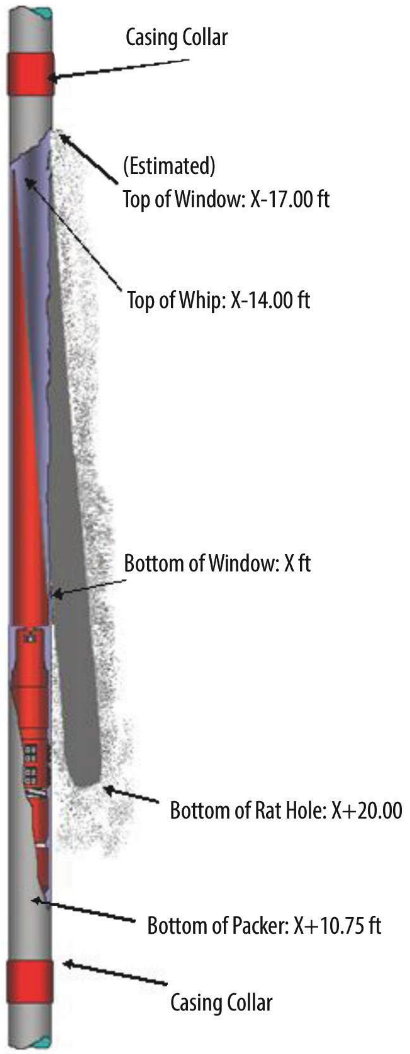
One of the other techniques that Apache introduced is what it calls pilot-hole drilling. "We'll drill several sidetracks from a single well. We may evaluate two or three targets. We'll drill to one target, plug it back, drill to another, plug it back and drill to a third one. That may create more targets that we'll drill later to produce. We'll complete, say, the final target," he said.

That's basically to optimize slot usage, which is one of the limiting factors. The company is building reserves by proving up new targets, but at the same time it ends up with a producing well. "It's like a mixture of exploration and development all in one wellbore," he added.

Producing through drillpipe

Hibbert described one solution as one of those "oddball things that we have had to do on one or two wells, which has been the only way we could complete those. We cemented in the drillstring across the reservoir and back into the previous shoe. We then backed off the drillpipe inside the casing, screwed in a liner hanger, crossed over to the drillpipe and perforated the drillpipe. The wells successfully produced for a few years."

These were wells with quite bad hole-stability problems. Completing the well through the drillpipe was the only solution. Otherwise the



The Smith whipstock with the locked back whipstock face was used for low-side exits.

well would have to have been abandoned. "It was a bit unconventional, but we managed to get our money back," he added.

Upside-down whipstock anchor

In collaboration with a service company Apache has perfected what it calls the low-side whipstock. The method helps with reducing problems with milling windows in uncemented casing.

"We've perfected running the whipstock upside down so that we are milling the window out of the bottom of the casing. In a normal whipstock the milling might come off left or right of high side. What we'll do is drop out of the low side of the casing. This allows the casing that is left on the opposite side of the milled window to create a tunnel roof that prevents effectively the hole collapsing in the uncemented area," Hibbert explained.

By using a Smith Trackmaster whipstock, the whipstock face is locked back against the inside or roof of the casing preventing the whipstock ramp dropping back across the hole and preventing further reentry (see SPE paper 149625 for more detail).

Openhole gravel packing

Sand production is a major problem in the Forties area. BP previously had opted to manage the sand at the surface. To improve the runlife of the electric submersible pumps (ESPs) in the wells, which are about 45% of the well stock, Apache opted to use sand screens and openhole gravel packs to keep the sand downhole.

"Once upon a time the runlife of the ESPs was one or two years, three years if you were lucky. The longest-running ESPs now have up to seven years runlife. By getting those runlives longer you go back and service a well once every four or five years. That gives you more drilling time during the year rather than having to do workovers, which equals increased production," Hibbert said.

On the Echo Platform a gravel pack was done off the back of a supply boat to reduce cost. "That was the first time that had been done here. Rather than use a full-spread gravel pack boat, we got the kit on a supply boat. We had to have the certifying authority to verify some things. That worked out quite well," he continued.

Changing drillpipe

Some of the simpler ideas provide some of the better returns. Take, for example, drillpipe and tool joints.

"We carried out a review of drillpipe that was available on the market. Because we had only two mud pumps early on and the standpipe manifolds had been downrated to 4,000 psi, we were restricted with the flow rate in 12¼-in. hole sections," he explained.

The company brought in Drilco's 5½-in. TurboTorque drillpipe. The advantage of this is that the tool joint is the same size as 5-in. drillpipe at 6⅝-in. (no loss of rack back capability), and it has a larger inner diameter (ID). With the larger ID there is a lower pressure drop in the pipe. That allowed the 12¼-in. section to be drilled with higher flow rates since there was less pump pressure lost in the drillpipe and higher annular flow rates.

This tool joint is a connection that makes up faster than other drillpipe connections and also breaks out more easily, being about 50% of makeup torque, which fitted nicely with the company's iron roughnecks, he added.

Another benefit was that the pipe could be racked in the existing 5-in. drillpipe fingers because the tool joint was the same size. No racking capacity in the derrick was lost. "That was another North Sea first. No one else was using the TT550 pipe here. We've continued to use that successfully across all our strings," he said.

Conductors, wooden guide shoes

Apache has drilled some new surface wells, which has required driving conductors. Conductor driving hadn't been done since the early 1980s.

"To start the conductor driving, we've used some simple technology for guiding the conductors through the offset guide rings fitted to the jacket, using a wooden guide shoe. Previously the conductors had been fed through the offset rings using divers and a complex rigging procedure. That's a demonstration of both low and high technology, which has enabled us to drill several new wells," he noted.

Essentially it's a 26-in. wooden cone that goes into the bottom of the drive shoe, made out of laminated timber. Because it's almost cone-shaped it gets into the offset guides without the risk of going to the wrong side of the guide.

When the conductor comes to a halt in the soft seabed, the company starts hammering it in. That sheers the pins holding the guide cone in place, which allows the cone to ride on the top of the soil plug inside the conductor as you drive the conductor into the shallow formation. When drilling out the soil plug for the next section, all that is being done is drilling out wood—and that's easy to drill out and cheap, he explained.

Manipulating casing

One of the restrictions with the Forties platforms is the number of available well slots for drilling. Apache has developed some innovative ways of renovating and using those slots.

On one well the 18⅝-in. casing was corroded, and the top end of the well had to be rebuilt. "What we did was get a crossover built from the 26-in. conductor to a starter head. We then cut and pulled 9⅝-in. and a few joints of 13⅜-in. casing just below the wellhead. We cut out the rotten 18⅝-in. casing, which was cemented back to surface. We tied the 13⅜-in. casing back into the 26-in. starter head, which allowed us to sidetrack the well and install new 9⅝-in. casing.

"These innovative solutions allowed us to basically reuse a slot that would have been junked otherwise," he said.

Casing back-out tools were used on one well drilled from the recently installed Forties Alpha Satellite Platform (FASP). The well unsuccessfully tested a deep target, using a 10,000-psi wellhead. For the next well the wellhead needed to be changed to 3,000 psi to drill a Forties target. By using a casing back-out tool, the 13⅜-in. casing was unscrewed, and a new joint of casing was installed. That allowed the top end of the well to be converted to take the company's standard equipment.

In an effort to maximize the use of well slots on Forties Echo, two splitter wells were drilled through the two remaining conductor slots. No splitter wells had been drilled on the field before. The 38-in. by 36-in. by 35-in. conductors were set in the two remaining slots.

"We were able to go through the guides in the template, which allowed us to get four wells drilled. One of the wells had an issue, so in the end only three wells were completed. It allowed us to get the equivalent of three additional producing wells onto the platform," Hibbert said.

The two wells were literally side by side, an inch or so apart. For each side of the splitter, 13⅜-in. casing was run, followed by 9⅝-in. casing and then 7-in. liners. At the time, these were some of the longest 7-in. liners run, Hibbert added.

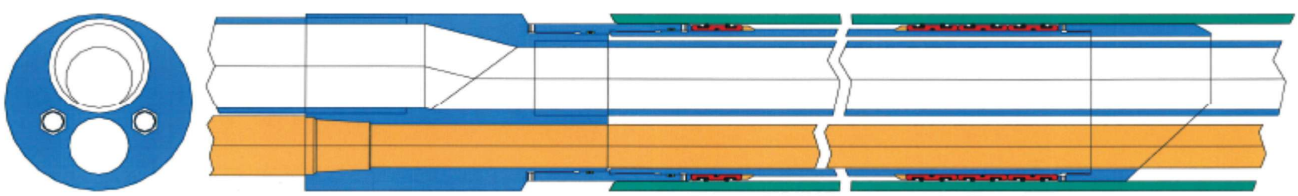
Ongoing innovation

The innovations are still going on with the Forties Field expansion.

These include horizontal trees to speed workovers and sidetracks, using seal cans in place of production packers, multibowl wellheads, extended reach wells to the Northwest Bravo Field, casing running tools and drilling into the reservoir formation in a single pass from the 13⅜-in. casing shoe.

All of these innovations have helped extend the productive life of this first generation giant field by another 20 years at a time when there are plenty of other North Sea fields being run down and preparing for decommissioning.

"Basically you have to have a can-do attitude, keep it simple, challenge the norm and think out of the box," Hibbert noted. "And to make it happen you have to have good people on- and offshore." ■



A liner top seal can was used in place of production packers. The tubing and ESP cable run through the seal can. Tubing is run into the seal can, and the hanger is set at the surface. To workover a well, the seal can is pulled straight out of its receptacle. It is a simple, cheap, effective method of sealing the wellbore.

Shale 2.0: Excelling in new commodity price environment

Advanced rig technology maintains drilling within the 'cycle-time sweet spot' to maintain wellbore tolerance in the production zone.

Mike Dynan and **Sean Roach**, Schramm Inc.

With WTI prices about $100 per barrel in October 2014, producers scrambled to find enough rigs, crews and equipment to meet expanding needs. It was inconceivable that just one month later prices would collapse, again transforming the oil and gas landscape.

A year later, as the headwinds of the new pricing paradigm continue to blow, the industry is split between those fighting to adapt and those whose products or operations enable them to flourish in the new cost-constrained environment.

New oilfield paradigm

"Shale 2.0" is Schramm Inc.'s nickname for the new U.S. oilfield operating philosophy—a mindset whose mantra is "efficiency optimization"—and an operating philosophy that has become a way of life amid a pricing recovery that is nowhere in (near) sight.

Operators are seeking ways to customize operations and equipment tailored to the asset they are working. They want the right tool in the right size for the right cost to squeeze every bit of value out of their operations—optimizing cost of extraction—to return to stakeholders. Operators who achieve this will be the new industry leaders, and it is the imperative of leading rig manufacturers to help them accomplish that goal.

Collaboration is key

Operators want to gain efficiencies in drilling operations but are frustrated by the one-size-fits-all production approach to drilling rigs. Many manufacturers offer bigger rigs with more horsepower but not necessarily rigs best suited to the demands of a particular basin or to the drilling solution an operator has in mind. When oil was $120 per barrel, that was fine.

Operators were willing to use whatever rig was available—and were willing to leave some meat on the bone when it came to efficiency—as well as absorbing the day rate associated with it. That era has ended. In this new era, operators are integrally involved in designing tailored drilling solutions that optimize efficiencies across their assets. Increasingly, they are collaborating with manufacturers as well as contractors, using a solutions-based approach to strategically choose the rigs and equipment optimized for the job required.

With a 500,000-lb hook load and world-class technology, the T500XD is the right tool for both horizontal and directional drilling. (Source: Schramm)

Right tools for right job

Schramm works directly with operators and drilling contractors to ensure that end-use customers achieve their desired efficiencies, particularly in wellbore manufacturing or batch drilling campaigns. This consultative approach involves opening the toolbox to give operators access to Schramm's entire diverse portfolio of rig solutions so they can choose the tools they want—where and when they want them—as they design their drilling programs.

Why is that important? It is because not all rock is created equal. The oil and gas industry is fortunate that the shale revolution accelerated knowledge of U.S. subsurface geology by leaps and bounds. Because the industry now understands the rock better than ever before on an individual formation basis, drillers are able to collaborate with operators and their contractors to implement a customized drilling solution based on their assessment of a specific basin's needs.

The company recognizes the need is not simply to be able to drill the hole in the fastest amount of time but to optimize the well's ultimate productivity—and that's the difference between being simply a vendor and being a trusted partner.

It is also important to understand that operators need to have the flexibility to choose the right tools regardless of vendors, so Schramm doesn't constrain customers by a requirement to use particular in-house drilling equipment or accessory brands. To maximize value, operators and contractors should have the freedom to choose any brands they believe are needed for a truly sustainable, fit-for-purpose solution.

Wrong tools provide poor results

At the height of the shale revolution, many operators discovered the cold truth about having too much rig power. Wall Street put tremendous pressure on operators to drive down cycle times, making powerful rigs very much "in style." Operators know now that drilling too fast can damage a reservoir and reduce the EUR of a well, rendering a field far less valuable than originally assessed. It is similar to trying to hammer a screw—using the wrong tool for the job and ruining the hole.

Advanced rig technology uses hydraulics to achieve power density while drilling within the "cycle-time sweet spot" to maintain wellbore tolerance in the production zone and to ensure the well maximizes EUR potential. These rigs have a smaller footprint, are easier to take down and self-erect and are able to walk and rotate 360 degrees, giving them more efficient movement from pad to pad and from well to well.

Thoughtful approach for better results

Smaller rigs also mean less surface disturbance, smaller crews and less traffic, which means happier landowners and communities. That is a key reason to offer off-the-shelf rigs that tap electrical highline power to drill horizontal wells all the way to total depth.

This is enabled through an electrical A/C grid-powered interface as a built-in feature on the rigs. In certain geographies, it is more cost-effective to drill with electricity, which lowers impact to nearby communities by eliminating onsite emissions and nearly eliminating noise.

Operator control rooms on the T500XD and T250XD are equipped with joysticks and large touchscreens that allow rapid navigation to all operational and diagnostic data from the rig. This makes real-time data from any sensor in the system literally at a user's fingertips. With an active internet connection, the live data can be transmitted to any connected offsite location. (Source: Schramm)

These qualities enable the rigs to get to total depth in the same overall amount of time as other rigs but with reduced environmental and community impacts and better well performance. In short, all operators can achieve efficiency in a more environmentally responsible way.

Safe operation is ultimate efficiency

Reliable operations are safe operations. To minimize lost-time incidents and maximize efficiency by reducing downtime, it is important for rig manufacturers to offer ongoing training to recertify crews, which ensures the best and safest possible operations. But more has to be done.

That's why Loadsafe automation technology was created to enable 100% hands-free pipehandling, eliminating the need for people on the rig floor and monkey board, the highest-risk areas on a rig.

New chapter

The industry has seen a monumental shift in thinking over the past several years—from the idea of global peak oil to U.S. oil exports. Today, in the midst of this shift to Shale 2.0, the new chapter in oil and gas development, the industry is increasingly embracing the "right tools for the right job" approach to ensure economically sustainable operations that optimize efficiencies and cut costs. Those who recognize the value in this approach are best positioned in this new industry era of Shale 2.0. E&P

Thermoplastic composite pipe was bound for Petronas in Malaysia. (Source: Airborne Oil & Gas)

A material world

The use of composite materials has been steadily growing over the past decade, with the latest applications offshore signaling that operators are now starting to more fully embrace their potential.

John Sheehan, International Editor

Airborne Oil & Gas of the Netherlands has a unique technology for producing thermoplastic composite pipe (TCP) of up to 10 km (6 miles) in length, depending on diameter, that can be applied to a variety of oil and gas applications.

Significantly, the company recently notched up a world first with a deal to supply a TCP flowline for a pilot project offshore Malaysia for national oil company (NOC) Petronas. The deal, which resulted from the successful completion of a three-year qualification program with the NOC, includes the delivery of a 550-m (1,805-ft) TCP flowline; ancillaries; and offshore installation, engineering and field support. The 6-in. flowline will be installed in 30 m (98.4 ft) of water and will connect two platforms on the West Lutong Field.

In addition to Petronas, Airborne also is working with Shell, Chevron, OneSubsea, Saipem and many other contractors and operators. Bart Steuten, development manager, said, "We are working on a Shell project for delivery of a downline system for well intervention in Nigeria. We also recently delivered a downline system for IKM Testing that will be used on the Aasta Hansteen Field by Subsea 7 for Statoil." The TCP downline will be used for the precommissioning of risers and pipelines.

Steuten continued, "We are putting our first pipe in the water for Chevron next year—a jumper for the Alder project in the U.K. North Sea. It is a relatively small-bore pipe, a 120-m (394-ft) jumper connecting a manifold to a wellhead. It is a pilot for Chevron. Once we have installed the first one, they will get to know our products and hopefully more will follow.

"We also are talking to a lot of companies for first flowline applications. People are always anxious to not be first, but as soon as we have the pipe in the water for Petronas, we're confident many will follow."

Interest in Airborne has been growing, with plastics specialist Evonik recently taking a minority stake. The investment was made jointly with HPE Growth Capital and Shell Technology Ventures.

Aerospace lift-off

The company itself was founded in The Hague in 1995 by two aerospace engineers who had the idea of using composites not only in their own engineering field but other industries as well.

Near-neighbor Shell then approached them in 1999 with a request to manufacture composite pipe. "That was the start of Airborne starting to develop technology for composite pipe," Steuten said. "The technology to make continuous pipe from composites didn't exist at the time. Many people could make short sections of pipe, but what was missing was a way to manufacture pipe in an endless way. That is what Airborne is all about."

In 2007, after a number of developments in the manufacturing technology, a separate business unit was established—Airborne Composite Tubulars, which was devoted solely to pipe. It later became Airborne Oil & Gas (AOG).

To manufacture its specialty pipes, Airborne has turned to thermoplastics and moved away from traditional thermoset materials, which require a chemical curing oven process that makes it difficult to make continuous pipe.

Steuten said, "Airborne developed a concept of TCP that starts with a plastic tape material. It looks like Scotch tape, but it is a plastic tape with glass fibers embedded in the plastic. The pipe consists of a liner, and then you have multiple layers of the tape material, which is wound around the pipe in a helical fashion. Then it is *in situ* consolidated, melted together to become one solid wall, and then we top it off with the coating. That gives a solid pipe that can best be compared with a solid steel pipe rather than a flexible or unbonded pipe."

Airborne uses a number of different materials to manufacture its pipes, including PA12 plastic, polyethylene, polypropylene and polyvinylidene fluoride, depending on the application, temperature and whether it's to be used for transporting hydrocarbons or not.

Steuten continued, "The plastic is always the same throughout the pipe; otherwise we cannot fuse it. We use one plastic to get the solid wall concept. It is solid, yet it is flexible, and the flexibility comes from the glass fiber and the way we wind the fiber.

"We change the fiber angles to get the optimum pipe design. If we need a pipe that has to be very flexible, we use a design that is plus or minus 55 degrees, and we get a pipe that is optimized for pressure capability and flexibility. If we want a pipe with more tensile capability for deep water and large weights to carry, then we adjust the angle. This way we can tweak the pipe to accommodate specific design needs."

Advantages

There are three main advantages of AOG's composite pipe, Steuten said: its strength-to-weight ratio, its flexibility and the fact it is noncorrosive. "The way the pipe is manufactured, it is still flexible and can be spooled. We deliver it on reels. We can make it in endless lengths, and it is very easy to deploy. You don't need to weld short lengths of pipe.

"Our process is unlimited in length, but what gives the limitation is the capacity of the reels and the carousels here in the factory. We can make 8-in nominal steel pipe in lengths up to 3 km [1.8 miles], which is the biggest we can get on the current carousel. But there are no fundamental impediments to produce longer lengths in the future. If you go to the smaller 4-in. diameter, we can already go to 6 km [3.7 miles] in length."

For a 5-km (3-mile) flowline on the seabed, two of Airborne's pipes could be connected using a flange.

For Petronas, Steuten said the attraction of using the TCP solution as a flowline was its noncorrosive nature. "This pipe solves any corrosion problem you may have. There is nothing in the pipe that will corrode. In that area of Southeast Asia there are tremendous corrosion issues, and our pipe is a solution to that.

"The Petronas job has sparked a lot of interest in Southeast Asia. It is a solution for many companies in the area whose pipes are affected by microbiologically induced corrosion caused by H_2S [hydrogen sulfide]."

Staircase strategy

Airborne adopted a "staircase strategy" to get its product into a very conservative and risk-averse market.

"People like new developments, but nobody wants to be first and be responsible for anything that could go wrong in the future with things that have not been tried or tested before," Steuten said. "We have adopted a staircase approach. We gradually increase the complexity and technical difficulty of an application. We take it step by step and start with relatively easy applications with a lower risk profile."

One of Airborne's first projects with Saipem was for a downline for pipeline precommissioning, with the TCP used for pumping water, glycol and air. "This was relatively low-risk, but we could prove the concept and make the client comfortable with our technology. The next step is to move from lower risk to slightly more risk and from a temporary to a permanent operation. The jumper for Chevron is for methanol and vent lines, which is a permanent application for 15 years. We have proven it is good for 15 years. This is another step in the technology staircase," Steuten said.

According to Airborne, the cost factor is another important element. "We realized that manufacturing composites is more expensive than steel pipe, so we deliberately selected relatively low-cost plastic and glass-fiber materials for our entry strategy rather than high-end plastic materials good for high temperatures," Steuten said.

The company has qualified its design methodology, manufacturing technology and materials testing with DNV, so it can offer its clients a comprehensive qualification system. DNV has carried out a joint-industry project on TCP with 19 companies, with an industry standard recommended pratice that was issued in November 2015. E&P

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High power-density motors enable rigs to drill more efficiently

A motor with higher power density can deliver more power with comparable weight or, similarly, comparable power at a reduced weight or size.

Alder H. Crocker and **Dan Cook**, Ward Leonard

For more than 50 years drilling rigs have been using modified locomotive traction motors for top drive, rotary table, mud pump and drawworks use. These large and heavy motors were first installed as an iterative solution to provide more power to drill the hole than the then-standard smaller, less powerful motors—and as a stop-gap to the intensive task of engineering new motors specifically tailored to achieve peak efficiency for each application.

However, as demand continues to increase for companies to develop solutions that reduce total operating costs while still being able to push rigs to drill deeper, faster and more efficiently—especially in the current market—it is more apparent that new motor technologies need to be at the front line of innovation for companies to achieve their individual strategic and operational goals.

Next generation of drilling motors

Ward Leonard has optimized four distinct but integrated areas that have an immediate impact on improving performance and productivity: motor size, weight, horsepower and torque.

The result is the industry's first line of high power-density AC-induction motors that use advanced thermodynamics and applied physics to deliver up to 50% more power and torque within the exact same motor frame size that is currently standard for each application.

The motors range from 450 hp to 2,000 hp; are purpose-built for top drives, mud pumps, drawworks and rotary tables; and feature proprietary intra-slot cooling technologies and fully optimized copper-to-steel ratios to achieve high-performance capabilities.

With high power-density motors, rig builders, drilling contractors and systems integrators are now able to develop the innovative rig and application designs they envision to drive the industry to greater efficiency.

	Standard 400-hp Motor	High Power-Density 600-hp Motor
Dimensions [W by D by H]	**19.6 in. by 19.8 in. by 47.9 in.**	
Weight [lb]	2,800	2,800
Rated Power [hp]	400	600
Torque [lbf-ft]	1,795	2,685
Current [Arms]	350	470
Speed [RPM]	1,172	1,163
Voltage [Vrms]	575	575
Frequency [Hz]	40	40
Volume-Power Density [hp/ft^3]	37.2	55.8
Mass-Power Density [hp/ton]	286	428

This table shows the comparison between a standard motor and a high power-density top drive motor. (Source: Ward Leonard)

High-power density defined

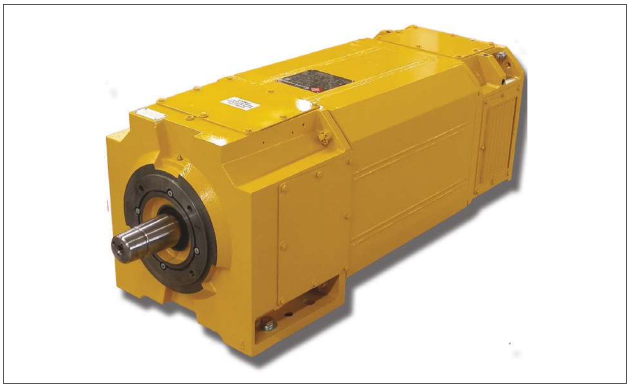
As it relates to electric drilling motors, power density can be defined as the ratio that describes the total rated power of the motor relative to its weight (power-to-weight). A higher power density, therefore, enables a motor to deliver more power with comparable weight or comparable power at a reduced weight.

Another form of power density can be defined as the ratio of total rated power of the motor relative to the volumetric footprint required (power-to-size). Again, a higher power-density motor can therefore deliver more power at a comparable size or comparable power at a reduced size.

Ward Leonard's solutions use both principles to enable users to achieve peak power performance and greater cost efficiencies throughout their operations.

Top drives

The advantages of high power-density top drive motors can be significant. Because the primary duty of the top drive is to spin the pipe while drilling, the depth of



The WL12BB060 top drive motor delivers up to 600 hp in a 400-hp standard 'square-style' frame and is 1,200 lb lighter than a standard 600-hp drilling motor. (Source: Ward Leonard)

the hole is therefore limited by how far the pipe can go and keep spinning. To keep the pipe spinning at greater depths, higher torque is required to overcome the friction of the hole wall.

For directional drilling, the pipe must both spin and bend at the same time. Higher torque provides the power to keep the drill from getting bound up. With top drive motors that deliver up to 50% more torque and horsepower, operators now have the ability to:

- Grind through more difficult geologies;
- Overcome friction in the hole wall at greater depths;
- Jog the pipe faster and with more power when a pipe bind occurs;
- Make longer horizontal runs;
- Drill and complete deeper holes faster; and
- Thread larger diameter pipes—and therefore drill larger holes—without changing rig tonnage or top drive apparatus, motor, drives and other associated equipment.

The company offers five motors for top drive applications ranging from 450 hp to 1,350 hp. Its WL12BB060 "square-style" motor delivers up to 50% more horsepower and 50% more torque than standard 400-hp frame motors (600-hp and 2,725 torque lb/ft) and weighs 1,200 lb less than a standard 600-hp frame motor.

Mud pump, drawworks

Fundamentally, the faster a hole can be drilled and completed, the faster it will become an income-producing well. Mud flow capacity is critical as it impacts the speed the drillhead can spin, and the pressure of the mud itself directly impacts the bite of the drillbit—both of which come from the amount of torque delivered by the mud pump motor. With high torque and horsepower motors, operators can expect:

- More mud flow capacity and mud pressure;
- Faster drillhead spin rates;
- Drillbits that bite more;
- Ability to drill through consistent formations at faster speeds and tougher formations at the same-as-current speed;
- Elimination of the need to swap out mud pump sleeves to accommodate higher pressures at the same flow; and
- Faster completions, which means fewer total drilling days.

As it relates to drawworks, the space a typical unit takes up is critically important. More space occupied equates to more overall cost. With compact high-horsepower high-torque motors, operators can improve productivity without increasing size or weight, pull up the pipe faster from greater depths, overcome intense friction and massive weight, increase overall performance and productivity and complete wells faster and reduce total drilling days.

Ward Leonard offers multiple high power-density motor options for mud pump and drawworks applications—ranging from 1,350 hp to 2,000 hp. Its 2,000-hp (WL29BC200) motor delivers 33% more horsepower than identical-sized 1,500-hp motors and is 14% smaller and 10% lighter than similar 2,000-hp motors.

Changing economics of drilling

Similar to Moore's Law, the power required for drilling motors will continue to increase because there are formations operators currently can't drill into with today's technology or won't because it isn't cost-effective enough.

High power-density drilling motors take operators to the next level. Not only do they essentially "supercharge" the capabilities of each application and their position in the value chain; they usher in a new lens for analyzing overall economics.

The benefits of using these compact lighter, higher horsepower and torque motors can result in deeper, faster and more efficient drilling with less downtime; less days to drill and complete; fewer motor burnouts due to enhanced cooling properties; reduced maintenance, repairs and spares costs; greater portability moving from site to site; reduced transportation costs and road weight fees; more flexible skid arrangement and reduced potential for wide and heavy loads; easily retrofitting existing applications without changing equipment designs; and greater flexibility to develop innovative rig designs that will themselves improve performance and productivity. E&P

Dustbuster for frack sand

New technology coats each grain to create a near dust-free frack sand.

Jim Sadowski, Superior Silica Sands

In a world where technology advances seemingly at the speed of light, it is only natural that the proppant industry would be on the cutting edge of new technologies. One such technological advancement is the patented process that ensures a clean, near dust-free frack sand. The technology was recently introduced by Texas-based Superior Silica Sands.

Called SandGuard, the technology will ultimately save operators money on the cost of wellsite activities as well as reduce the wellsite footprint by eliminating much of the current mechanical dust collection equipment being used to collect dust on site.

Regulatory need

Exposure to fine silica particles has been known for many years to cause silicosis in workers exposed to silica dust over long periods of time. The U.S. Occupational Safety and Health Administration (OSHA) has regulated silica exposure for many years with a permissible exposure level of 100 micrograms per cubic meter for workers in all industries, including the oil and gas industry.

However, OSHA has determined that this exposure limit does not adequately protect workers and proposed in 2013 that the permissible exposure levels of crystalline silica over an eight-hour period be reduced to 50 micrograms per cubic meter. The lower exposure level has not been adopted in the U.S. due in part to the difficulty of achieving these levels in the industrial setting. This regulation has been adopted by the Canadian Center for Occupational Health and Safety but has not been enforced due to the same difficulties of implementation in the industry.

Reduction solution

Developed in partnership with ArrMaz Chemical Co., SandGuard is a product developed using the SandTec coating system and proprietary aqueous coating chemical. The key to the product is obtaining an extremely even coating of each sand grain while using a very minimum amount of the coating chemical. When this is achieved, the dust generated from particle-to-particle contact throughout the many mechanical or pneumatic transfers during the transit time from when the proppant leaves Wisconsin to the final use point has all but been eliminated.

Field trials with a major service company have shown the technology allows near dust-free sand upon arrival in the basins. Standard personal dust monitoring equipment, worn by employees during normal handling and well completion operations, showed silica exposure limits were below 25 micrograms per cubic meter. These silica exposure levels were well below the current as well as the new proposed limits and therefore are in compliance with the proposed OSHA regulations without the aid of any mechanical dust collection.

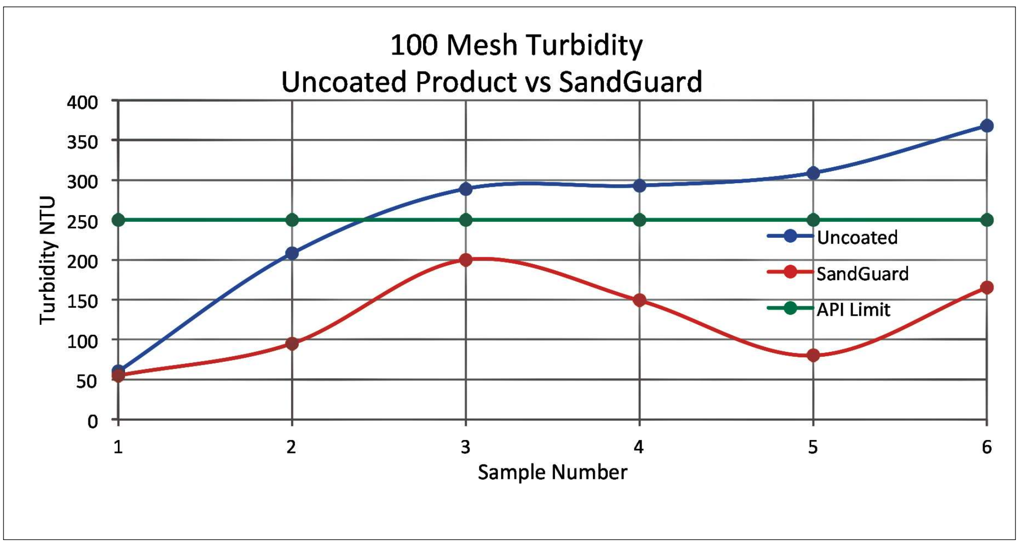


FIGURE 1. The turbidity of SandGuard frack sand as compared to uncoated frack sand is shown. (Source: Superior Silica Sands)

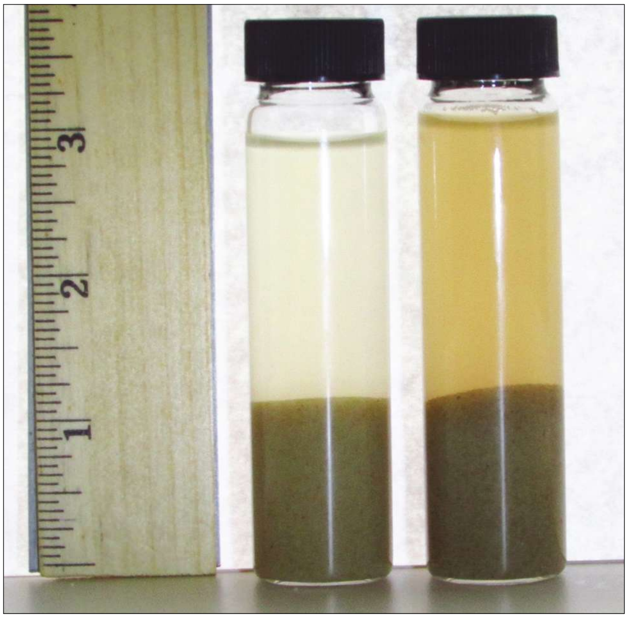


FIGURE 2. Shown are samples of SandGuard (left) and uncoated sand (right) after settling out for 30 seconds. (Source: Superior Silica Sands)

Since the "dust collector" is built into the product, the dust is controlled from all potential dust-emitting sites. This will not only positively impact the workers, but visual dust emissions also will be eliminated.

Additional benefits

Although the main purpose of the product is to protect the workers from silica exposure, it also has additional benefits to the oil and gas industry. Testing has shown that turbidity of the product is lower than traditional uncoated sand. This is especially true in the finer products like the 100-mesh product as shown in Figure 1.

The data show that the turbidity (NTU) of the product was consistently below the uncoated sand values. Even when extremely high turbidity sand was tested (over American Petroleum Institute [API] limits), the turbidity values were reduced to within the API specification. Perhaps a better way to evaluate the turbidity is through visual observations of the SandGuard frack sand vs. a standard sand. Figure 2 shows the difference in turbidity between the two samples. For the test, near equal amounts of both products were mixed with water and shaken until thoroughly mixed. The samples were allowed to settle for 30 seconds prior to the photographing.

Although not shown, after 24 hrs, the uncoated sample continued to have noticeable turbidity, whereas the SandGuard sample was completely clear and was crystal clear after 8 hours.

To further understand the improvement in turbidity, an additional test was conducted in which uncoated sand and SandGuard frack sand were aggressively mixed in a laboratory environment to simulate the many transfers that occur from the time the sand is shipped from Wisconsin to its final use area. These tests showed a remarkable improvement in turbidity using the SandGuard product, with the NTU being reduced by greater than 55%.

Performance

Though it is a coated product, the coating is applied with an exceptionally minor amount of chemical. As such, the material handling properties of the product do not differ from traditional sand products. For example, angle of repose for the product is 33 degrees (+/- 2 degrees) for 20/40, 30/50 and 40/70 mesh product and increases to 35 degrees for 100 mesh. This compares favorably to traditional sand angle of repose. These tests were conducted at temperatures ranging from -20 C to 100 C (-4 F to 212 F) with no noticeable difference in flow characteristics.

Although it has been proven that the product will significantly reduce dust, it still needs to be able to perform downhole. Tests by several different service companies have shown that the chemical used is compatible with the fluid systems that are currently being used in the industry. The chemical is one that is generally recognized as safe, is water soluble and is utilized in very low dosages. Testing in multiple wells has proven that there are no detrimental effects with the use of the product, making it safe and practical for the oil and gas industry.

The product was originally designed to limit dust exposure to the workers in the oil and gas industry, including the transload sites. Tests have shown that exposure levels to workers can be less than one-half of the OSHA proposed silica levels of 50 micrograms per cubic meter. In addition to helping safeguard workers, it also has been proven that the product lowers turbidity levels and improves the conductivity and permeability.

At the same time, the flow characteristics of SandGuard remain unchanged, with no adverse effects on any pumping fluids. The product is a stepped improvement over current products in the industry and is expected to have longevity due to its dust mitigation properties throughout the supply chain as well as protecting the integrity of overall well performance. E&P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An intelligent approach to basin modeling

Investing in reservoir intelligence enhances economic returns in today's reservoirs.

Allen Howard and **Jeff Bayless**, Nutech USA

When doctors wish to gain a better understanding of what is going on inside a patient's body, they will perform an X-ray to construct an "internal map" of the body and, using their years of experience, will analyze the representation it produces and recommend a best course of action based on what they see. In oil and gas basin modeling, the same concept applies.

Nutech offers an integrated set of technologies that together provide a comprehensive and evolving picture of a reservoir across the entire life cycle of an asset via five areas of expertise: petrophysical analysis, core analysis, completion engineering, reservoir mapping and modeling, and reservoir engineering. The company has named this collective approach "reservoir intelligence."

Reservoir intelligence is the integration of a number of these five disciplines related to reservoir modeling with the aim of extracting as much information as possible from the available data. Similar to combining multiple technologies like MRI and CT scans, the purpose is to provide the best understanding of what exactly is going on under the surface. The enhancement of knowledge and understanding that this approach provides enables companies to add value with improved intelligence and the ability to make better business decisions.

Disciplines in reservoir intelligence

Reservoir intelligence is assimilated by experts in five in-house teams and gathered using innovative technology and processes. NULOOK, for example, is an enhanced petrophysical analysis that uses conventional openhole well logs and forms the basis of integrated reservoir characterization processes that are used across all disciplines in reservoir intelligence. In the realm of completion engineering, the NUSTIM completion process is an eight-step design procedure that links a normalized reservoir textural analysis to past well records and history obtained in a field. Once this linkage is established, the process is then used to predict well behavior prior to completion. By way of this process, the optimal completion strategy for a new well or recompletion opportunity for an older well can be achieved.

In the realm of static property modeling, the NUVIEW process takes advantage of the textural analysis and the key petrophysical outputs to build models that allow users to calculate original oil in place and devise infield development plans. In the realm of dynamic modeling and simulation, NUVISION connects the dynamic behavior of reservoir fluids pressure and well completion and production information to the equation of field and reservoir development optimization.

Knowledge is power

In today's low-cost environment, knowledge is power. Increasingly, oil companies need to maximize the use of their own data and the public data available to them. Often companies invest significant capital in acquiring data and information, drilling and logging wells, and taking samples of rock out of the well location and having the cores analyzed. However, optimal use of the data is not always achieved, and wells are continually drilled with no data collected at all.

By making full use of all the available information and using a combination of approaches to fully understand the reservoir and develop reservoir intelligence, better decisions can be made that take into account all of the different property variations across the basin and ultimately improving economic return.

Leveraging external expertise

There are many small oil companies that do not have either the expertise or the in-house tools required to perform effective basin modeling. By incorporating the reservoir intelligence group as part of their asset team, companies like these can leverage advanced technology and resources to work alongside their team.

The process works as follows: A client drills a well and a model is built using well, seismic and other available data. That model is then used to deduce what would happen if another well was drilled in certain locations or if two or three wells were drilled. The data are processed to characterize the reservoir, and then a model is built. Scenarios are modeled before investment is committed to drilling and completions. This is performed via an ongoing process of simulation and choosing the best location for the

next well, drilling that well and updating the model in a continuous process over the years.

Shale basins: viewing the old through new eyes

In each basin the company has about 17 different studies. These shale studies (or basin studies) are distributed through all the major shale plays in the U.S. and Canada, with some in Europe and globally (Figure 1).

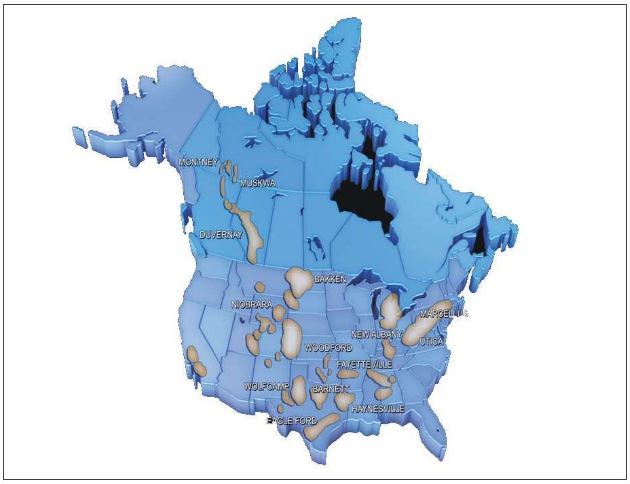


FIGURE 1. This map outlines the major petroleum basins in North America. (Source: Nutech)

The company specializes in building a better analytical model using vintage data. The decision was made to look at older wells that were originally drilled for conventional reservoirs, bypassing the shale in a time before shales were considered valuable. The log data from these wells is now, after a period of time, publically available.

A database of these wells was constructed and a logging analysis method was developed to determine the characteristic of the reservoir (Figure 2). The reservoir characterization from these older wells and well logs enabled the construction of basin models, which are large 3-D models of the entire basin using key outputs and the shale vision processing to distribute the shale properties across the entire basin. These 3-D models are converted into maps, and clients can then see where the optimal areas are located within a basin and focus their efforts accordingly.

A number of different shale properties are modeled: petrophysical properties like porosity and shale permeability, structure, net thickness, water saturation, oil or gas in place, and geochemical composition of the basin is analyzed. This all enables a calculation of the in-place hydrocarbon, extraction strategies or the value of the basin for targeting different acreage positions within the basin.

The basin studies are updated with additional wells as the information becomes public. Since there are increasing amounts of production data from the operators, the production or the well performance aspects are being incorporated alongside static reservoir properties to determine a better, more accurate representation of which properties impact well performance. With this information, the team can identify which property or which combination of properties predicts well performance and can forecast what a typical well would perform like in new locations within the basin.

A transparent conclusion

Being able to analyze large static property models across the basin allows the company to perform additional work with clients to optimize well completion, spacing and placement within the reservoir to extract as much hydrocarbon as efficiently and economically as possible. An area can be cut from the large model to build a higher resolution model of the selected area. Dynamic simulation work can then be performed on the smaller model.

Reservoir intelligence gathers all the data that illuminate the properties of a reservoir in an integrated fashion. The purpose of doing this is to improve overall knowledge about the reservoir. In turn, this knowledge fosters an improved degree of intelligence behind the decision-making processes in determining the most economical way of extracting hydrocarbons. E&P

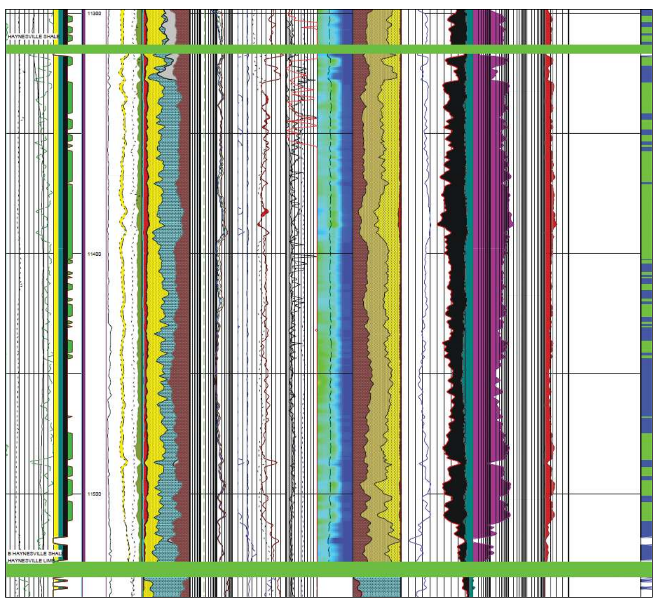


FIGURE 2. NULOOK is a petrophysical analysis using openhole well logs. It forms the basis of integrated reservoir characterization processes. (Source: Nutech)

Bringing new technology to an old field

A full static model in a highly complex structural and stratigraphic environment provides greater subsurface understanding.

Bruno de Ribet, Paradigm

The Middle Magdalena Valley Basin, located in the central part of Colombia, has evolved through many stages, resulting in a highly complex structural and stratigraphic framework. Exploration in this region was initiated in 1955 and, until recently, the available data have never provided an accurate image of the reservoir for developing successful drilling plans for various reservoirs. After many years of oil production, some results of recent drilling campaigns have demonstrated that various reservoirs in the basin have not been accurately mapped, leading to sub-optimal exploitation. The main challenge of current planning is to understand the geometry and kinematics of the basin, provide new insight into the tectonic setting and gain a clearer picture of the migration and trapping of hydrocarbons in the various reservoirs. To accomplish this, geoscientists need to build an accurate geologic model to add information regarding the location of potential resources and help to perform a valid volumetric evaluation.

Setting

The Middle Magdalena Valley Basin is an intermountain basin located in northwestern Colombia between the Central and Eastern Cordilleras of the Andes Mountains. It is structurally bounded by the Palestina Fault to the west (dextral strike slip system) and the Bucaramanga Fault to the east (sinistral strike slip system). The basin is part of the Magdalena Valley, which includes the Upper Magdalena Basin to the south and Lower Magdalena Basin to the northwest of the Middle Magdalena Basin.

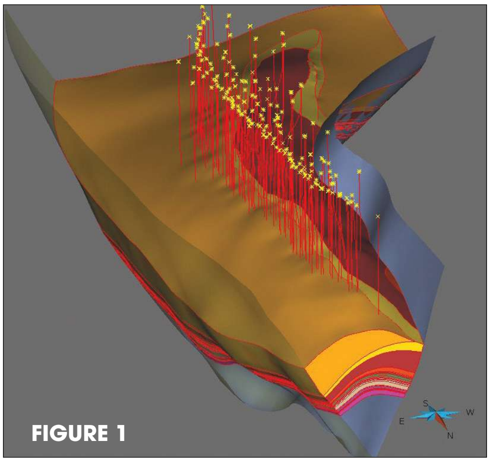
The basin is elongated. It is only about 80 km (50 miles) wide but extends to the north about 450 km (280 miles), where it terminates against the Santander Massif and Cesar Valley. To the south it terminates against the Upper Magdalena Basin, which consists of the Girardot and Nieva sub-basins where the Central Cordillera and Eastern Cordillera converge. Faulting in the Middle Magdalena Basin is primarily reverse and thrust faulting. Reverse faulting is high-angle in the west and low-angle in the eastern and central areas of the basin, with normal faults also developing along the eastern margin. These thrust faults formed from thrusting from the eastern margin of the Central Cordillera in the Eocene and the western margin of the Eastern Cordillera in the Miocene. Folds, which can be described as a series of asymmetric syncline against the hanging wall of the fault next to an inclined anticline, are key structures for hydrocarbon explorations. The structure from this case study is an asymmetric anticline limited to the east and west by major reverse faults.

Methodology

Previous studies had not succeeded in associating information from the 185 wells (22 stratigraphic units) and seismic interpretation data (reverse faulting and main horizons) in a unique 3-D geologic model. Based on the complexity of the structure and quality of the seismic data, only five horizons representing the main formations and 10 faults were interpreted. Conventional modeling solutions and technologies are mostly 2-D-based. Triangulated surfaces used to represent fault or horizons are difficult to bring in perfect contact with one another. Pillar grids represent horizons and faults together and do not suffer from the triangulated surface contact issues, but the fault network needs to be fully represented by a coherent set of pillars. This is not possible when fault contacts intersect one another or become horizontal.

Building a precise stratigraphy column from well markers, seismic interpretation and the deposition mode paired with a unique pillar-less full 3-D approach provided a true representation of the complexity of the reservoir. This was done through an accurate static model, which in turn provided a more reliable model for reservoir properties modeling and simulation workflows.

This pillar-less approach is based on the concept of a space/time mathematical framework introduced by Mallet (2004, 2014). In this approach, any subsurface is curvilinearly parameterized by a uvt-transform: it maps every point, defined by x, y, z in the geological space into the paleo-space by its u, v, t coordinates. The uvt-transform is computed so an iso-t surface corresponds to a stratigraphic horizon, and an iso-t is discontinuous



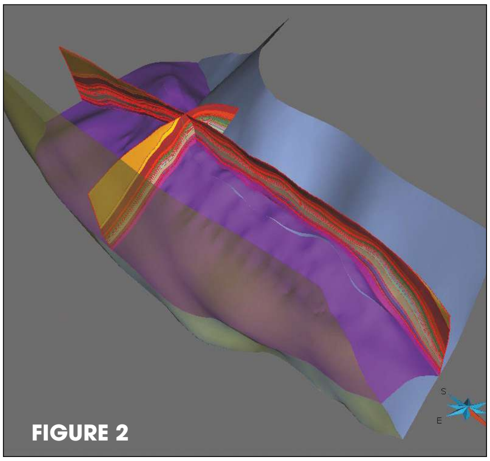


FIGURE 1. The final structural and stratigraphic model is a more accurate representation of the geology. (Source: Paradigm)

FIGURE 2. Visualization of the geologic grid for the reservoir of interest will be used to propagate the petrophysical properties of the reservoir. (Source: Paradigm)

across the faults. If the seismic reflections, and therefore associated well markers, are assumed to be consistent with the chronostratigraphy (time-stratigraphic correlation), then seismic interpretation (even incomplete) and well markers are considered as iso-t surfaces of the uvt-transform. The regular way of building the uvt-transform is to assign a relative geologic time to each interpreted event (seismic and defined only by well markers) through the definition of a stratigraphic column and to interpolate the values across the volume of interest.

The uvt-transform removed the usual bottlenecks of traditional pillar-based technologies by representing complex fault networks without having to simplify the original information. Without pillars, geoscientists are able to create a more accurate model of the subsurface (Figure 1).

The algorithm delivered a consistent representation without "dumbing down" the data so that there was no need to take into account all the available data (seismic interpretation, well markers) to ensure an accurate image of the subsurface. This process allowed 22 stratigraphic levels to be created from five interpreted horizons and well information. The final model was a full, perfectly sealed structural model. The next stage, associated with the structural and stratigraphic model (static), was to build the geologic grid, which will be used to propagate the petrophysical properties of the reservoir (Figure 2). Geological grids for geostatistical simulation of rock properties were computed directly from the uvt-model without any additional user interaction. These grids can be used for velocity modeling or geological modeling.

In this project, the next challenge was to understand the internal distribution of the facies within the reservoir. Reservoir facies determination is one of the uncertainties in reservoir modeling studies. It will affect the reservoir properties distribution, and inappropriate determination of the facies distribution may give unrealistic reservoir behavior. Integrating the petrophysical data from the wells combined with a conceptual deposition model from sedimentology maps enabled the creation of a 3-D facies proportion cube. This provided the geological background for all the property models.

Three-dimensional reservoir models play an essential role in the assessment of hydrocarbon resources. They not only are used to estimate in-place volumes but are also the primary input to flow simulation for optimizing and forecasting how much resource can actually be recovered. Uncertainty in hydrocarbon volumes is typically assessed through multiple realizations of the reservoir model's petrophysical content.

Using an accurate subsurface geologic model, it was possible to quantify and model the uncertainty related to each property and come up with a wide range of geologically feasible stochastic scenarios to define the impact of uncertainty when estimating the reserves, ranking the degree of influence of each property in the reservoir volume calculation through spider and tornado charts. This workflow enabled the quality control and validation of the static model by integrating the dynamic data and by comparing the production history with the model prediction before performing simulation.

The first result of this project was a validated, accurate structural and stratigraphic model containing 22 stratigraphic units that honored both the seismic interpretation and well markers. The geologic grid created from the final structural model honored both the geology and stratigraphy. A solid statistical analysis of the petrophysical well properties was delivered, as were property models honoring sedimentology and petrophysical data. E&P

Cement-bond logging service improves wellbore integrity assessment

The use of electromagnetic-acoustic sensors holds the potential to significantly improve how cement integrity of wells is evaluated.

Rajdeep Das, Baker Hughes

Cemented tubulars provide isolation between the environment and flowing production fluids. Operators in the upstream sector of the oil and gas industry rely on the accuracy of cement-bond logs to make critical decisions that can affect long-term well integrity and the environment. Several downhole conditions, such as thick casings, heavy borehole mud and low-density cement, pose potential problems to the acquisition of representative cement evaluation data.

The most challenging conditions occur when cement becomes contaminated with borehole mud during the cementing process and when low-density cement is used. Both of these conditions decrease the acoustic impedance properties of the cement, which makes it invisible to traditional acoustic-based cement evaluation services.

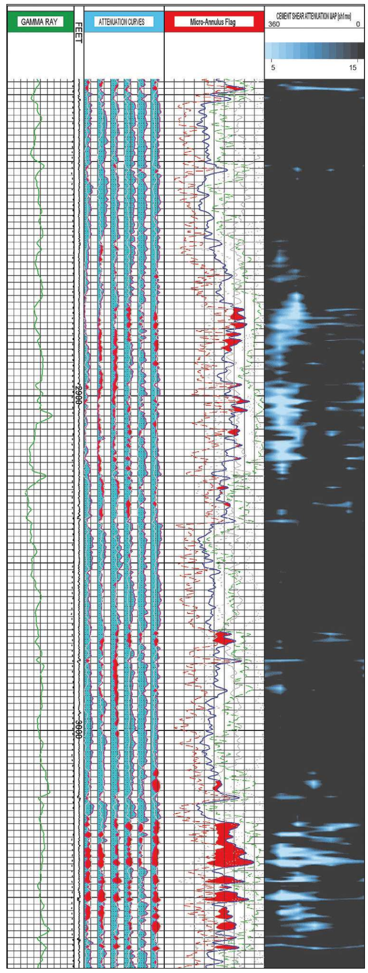
A new evaluation service that uses electromagnetic-acoustic transducer sensor technology holds the potential to significantly improve the way the cement integrity of oil and gas wells is evaluated. This new technology, which forms the basis for the Baker Hughes Integrity eXplorer cement evaluation service, allows operators to directly assess the integrity of cement bonds in any current wellbore environment or cement mixture.

Direct measurement of cement strength

While cement compressive strength has typically been used as a key indicator of cement quality, today's challenging environments require a more detailed assessment. The shear acoustic mode generated by the electromagnetic-acoustic transducers provides a new foundation for cement evaluation by responding to the cement shear modulus, which is a true indicator of solid cement behind the casing.

Radical change in low-density cement evaluation

Lightweight cements with densities as low as 7 parts per gallon (ppg) are used in the industry today to reduce the downhole cement hydrostatic pressure column to accomplish a seal across highly depleted and weaker formations without fracturing them unintentionally. It is estimated that 30% of new oil and gas wells use these lightweight cement slurries. Existing acoustic-based cement evaluation technologies rapidly lose dynamic resolution as the density of these cements drops below 11 ppg.



With a single pass into the wellbore, the new cement evaluation service enables detection of the presence of a microannulus and the quality of cement behind it. (Source: Baker Hughes)

These traditional services perceive contaminated or lightweight cement as a partial or nonexistent bond. The new service provides a noncontact excitation of shear and lamb acoustic modes that overcomes the challenge of evaluating these types of cements. The shear horizontal mode that is used to evaluate these lightweight cement slurries cannot be generated by conventional acoustic transducers.

The service provides accurate information that helps operators gain a better understanding of the cement-

bond—regardless of weight or contamination—to make critical decisions regarding long-term zonal isolation with greater confidence. Capable of accurately measuring the cement bond regardless of the type or presence of fluid in the wellbore, the service eliminates the need to unnecessarily add wellbore fluids for evaluation. By generating acoustic waves directly on the casing, measurements can be provided in air-filled boreholes and gas-cut mud systems.

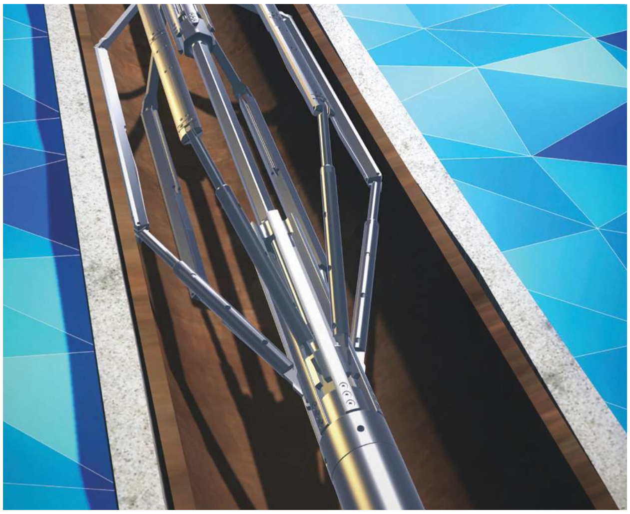
Identification of microannuli presence

Evaluation of the cement bond in zones with microannuli is critical for assessing the necessity of remedial cement squeeze jobs. When a microannulus is present, a thin micron-scale gap develops between the cement and casing. Conventional cement evaluation services perceive the casing as free, even though cement is present.

With the help of the acoustic lamb (flexural) mode, the electromagnetic-acoustic service eliminates the need for, and associated time and expense of, procedures to pressurize the casing for evaluation. In a single pass into the wellbore, the service's proprietary sensor technology enables detection of the presence of a microannulus and the quality of cement behind it.

Advantages in demanding environments

Tool eccentricity has historically posed a challenge to cement-bond evaluation services. The new service, with the help of its six-pad design, avoids this situation as the magnetic force present between the pads and the casing maintains physical contact between the two. The pads are designed and engineered to make the sensors insensitive to moderate tool decentralization. As a result, log quality is not compromised. This capability is valuable for demanding deployments in highly tortuous wellbores.



Pads designed and engineered to make the measurements insensitive to moderate decentralization help ensure log quality in highly tortuous wellbores. (Source: Baker Hughes)

The fact that the service can be used with the service company's existing fleet of wireline openhole formation evaluation instruments provides an efficient method of saving rig time by assessing the formation through the casing while performing the required cement evaluation. Data from the service are provided at the rig site.

The Integrity eXplorer cement evaluation service uses electromagnetic-acoustic transducer sensor technology to enable direct assessment of cement-bond integrity. (Source: Baker Hughes)

Successful cement evaluation in air-filled borehole

Operators in the northern U.S. store natural gas for future use in underground gas storage (UGS) wells. Evaluating cement for zonal isolation in these wells has proved costly because of the time and resource-intensive nature of the operation.

Conventional cement evaluation services require operators to relieve stored gas pressure, kill the well and fill the wellbore with liquid to achieve effective cement evaluation data. To minimize losses, operators wait until the well pressure is lower than the well discovery pressure. However, this condition typically occurs only once a year, significantly limiting the time when cement evaluation in these wells is possible.

To reduce operational cost, safety and environmental implications, operators need the flexibility to log these UGS wells for cement evaluation whenever desired. To address this need, the new cement evaluation service was applied in two gas-filled wells under pressure.

The service successfully provided cement evaluation data without fluids in the borehole. The data that were acquired matched previous data obtained from the same well several years ago in the presence of borehole fluids. This comparison gave the operators the reassurance they needed to ascertain the presence of long-term zonal isolation.

Operational and remedial expenses were significantly reduced by eliminating the need to set a plug, fill the well with fluid for cement evaluation and then reverse the process to restore the storage functionality. E&P

Drilling data deliver quality results

A new process provides successful completion placement on every well.

Dale Logan, C&J Energy Services

Over the last five years a number of publications and technical papers have addressed the impact engineered completions can have on the success of shale reservoirs. Early efforts to determine this impact focused on whether the degree of lateral variability warranted the effort and costs associated with an engineered approach. These studies pointed to the mismatch between the wellbore trajectory and geological trajectory, which is inevitable when drilling thousands of feet of lateral section each day.

Lateral variability manifests itself as variability in the stress profile along the lateral. The variations in stress have a direct impact on the completion efficiency within each stage because the frack treatment tends to follow the path of least resistance. If perforation clusters occur within a stage at relatively lower stress, then they will break down early and be overtreated, while the higher stress clusters will be undertreated. This occurrence leads to inconsistent treatment results and a corresponding inconsistency in production from stage to stage and from well to well. This result is referred to as the "statistical nature" of shale reservoirs.

Despite this, the engineered completion continues to be a workflow that has failed to gain universal acceptance. The engineered completion is still viewed as a "science project," not a mainstream workflow. Some of the reasons for this include:

- The high cost of data acquisition;
- The negative impact on operational efficiency;
- Challenging logistics in a high-volume arena; and
- The difficulty in quantifying the impact of the optimized completions on individual well production.

LateralScience has been designed to address these factors and pave the way for the deployment of engineered completions on every well. It is an innovative, out-of-the-box approach that focuses on a different source of reservoir information—drilling data.

The data being leveraged are common drilling parameters including weight on bit, RPM, torque (TOR) and differential pressure (ΔP). A key advantage to this method of reservoir evaluation is that these data exist on every lateral ever drilled, which directly addresses the first two objections to universal acceptance previously listed.

In 1964 Robert Teale published work that proposed the use of mechanical specific energy (MSE) as an effective way to optimize drilling practices using the drilling data listed above. The MSE parameter defines the amount of work required to drill a unit volume of rock, which will vary according to the geomechanical properties of the reservoir. Generally, completion engineers are not familiar with MSE, but they do recognize the parameter known as unconfined compressive strength (UCS). This parameter is typically measured in a laboratory on core samples and is then used to understand how the reservoir will break down under pressure during a hydraulic fracturing operation. The relationship between MSE and UCS is important; they are related by the drilling efficiency (D_{eff}) of the rig ($UCS = MSE*D_{eff}$). Assuming that D_{eff} is reasonably constant, MSE can be used as a good qualitative proxy to UCS. This assumption will be reasonable over short intervals of the lateral (i.e., the length of a frack stage, ~ 76 m [~ 250 ft]).

The work done by Teale successfully addressed vertical wells, but it was insufficient for the horizontal wells, which became popular some 30 years later. The actual equation currently deployed is still the same science, but it had to be adapted to account for the mud motors in the tool string. Teale's equation relies on the TOR measurement as an important indicator of the reservoir strength, which is typically adversely effected in most horizontal holes. The LateralScience approach leverages ΔP rather than TOR to better define rock strength in the lateral section of a shale well.

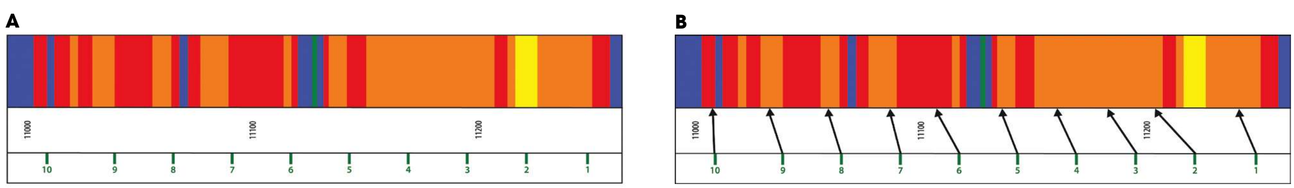


FIGURE 1. (A) The original geometric completion design with 10 perf clusters is shown. (B) The optimized completion design minimizes the effect of lateral heterogeneity. (Source: C&J Energy Services)

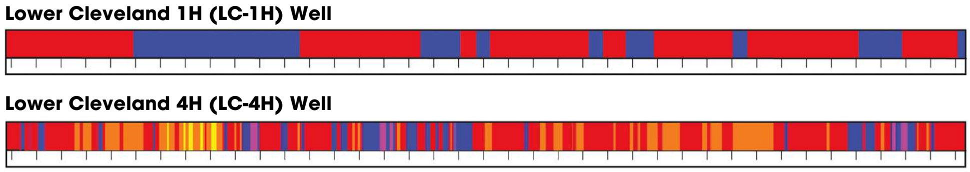


FIGURE 2. Two 1,006-m LateralScience facies plots of the LC-1H (top) and LC-4H (bottom) wells show that one well has significantly less lateral heterogeneity than the other. (Source: C&J Energy Services)

Workflow

For ease of use, the LateralScience workflow converts MSE into a facies log, with each facies representing a range of MSE values. The yellow facies is easier to drill than the orange facies which, in turn, is easier to drill than the red facies. While examination of the entire well is helpful, the real work is done one stage at a time. The workflow starts with the original geometric design, shown in Figure 1A. In this particular stage, 10 perf clusters are spaced 7.3 m (24 ft) apart. With the original design, perf cluster two appears to be an issue since it will break down early and ultimately receive a disproportionately high percentage of the stimulation. Figure 1B demonstrates how the perf clusters can be repositioned to alleviate this issue while maintaining a reasonable spacing between clusters. This optimized perf design increases the odds of getting an evenly spaced treatment across at least eight of the 10 perf clusters, which improves the productivity of this particular stage.

This facies-based approach is simpler to deploy than other engineered completion workflows, addressing the concern of being able to deploy this technique in a high-volume, high-efficiency manner.

Case study

An important step in validating this approach is to demonstrate that LateralScience can differentiate between a well whose production is adversely affected by lateral heterogeneity and a well that is producing optimally. This case study compares two wells drilled in Ellis County, Okla., in the Lower Cleveland sand, a silty sandstone. These two wells were selected by the operator for evaluation because they were in close proximity (<1.6 km [1 mile] apart) and were drilled parallel to each other (due north). The two wells were completed in a similar fashion and yet had significantly different production results. Both wells were completed geometrically with identical schemes (20 stages, four clusters per stage, stage length of 72 m [235 ft]) and were treated with identical frack programs.

A 1,006-m (3,300-ft) section of the LateralScience facies log from each of these two wells is shown in Figure 2, showing that the LC-1H well has significantly less lateral heterogeneity than the offsetting LC-4H well. The variability in rock strength at each perforation cluster is shown in Figure 3, giving valuable insight into variability in production between the two wells.

Assuming the weakest facies in each stage will be effectively treated, LateralScience predicts that 63 of 80 perf clusters in the LC-1H well were effectively stimulated. The same analysis for the 4H well yields 42 effectively stimulated perf clusters. The perf efficiency is 50% better (63/42) in the LC-1H well, which is in excellent agreement with the actual production data.

In the first year, the LC-1H well averaged 214 bbl/d of oil and 16,169 cu. m/d (571 Mcf/d), while the LC-4H well averaged 135 bbl/d of oil and 9,288 cu. m/d (328 Mcf/d) (58% more oil and 74% more gas). The excellent agreement suggests that the difference in production is primarily due to the effects of lateral heterogeneity and that LateralScience can detect this difference on future wells and enable the engineered completion design. E&P

LC-1H Well Completion Design

Stage	Plug Depth	Cluster 1	Cluster 2	Cluster 3	Cluster 4
1		14127	14067	14007	13947
2	13905	13892	13832	13772	13712
3	13670	13657	13597	13537	13477
4	13435	13422	13362	13302	13242
5	13200	13187	13127	13067	13007
6	12965	12952	12892	12832	12772
7	12730	12717	12657	12597	12537
8	12495	12482	12422	12362	12302
9	12260	12247	12187	12127	12067
10	12025	12012	11952	11892	11832
11	11790	11777	11717	11657	11597
12	11555	11542	11482	11422	11362
13	11320	11307	11247	11187	11127
14	11085	11072	11012	10952	10892
15	10850	10837	10777	10717	10657
16	10615	10602	10542	10482	10422
17	10380	10367	10307	10247	10187
18	10145	10132	10072	10012	9952
19	9910	9897	9837	9777	9717
20	9675	9662	9622	9582	9532

LC-4H Well Completion Design

Stage	Plug Depth	Cluster 1	Cluster 2	Cluster 3	Cluster 4
1		14160	14100	14040	13980
2	13950	13920	13860	13800	13740
3	13710	13680	13620	13560	13510
4	13470	13440	13380	13320	13260
5	13220	13190	13100	13050	13010
6	12910	12885	12860	12830	12790
7	12750	12730	12660	12600	12550
8	12510	12480	12390	12350	12300
9	12280	12250	12215	12120	12070
10	12024	11970	11900	11860	11820
11	11780	11740	11700	11650	11610
12	11560	11510	11475	11385	11330
13	11310	11300	11200	11115	11090
14	11030	11000	10950	10900	10850
15	10815	10800	10740	10710	10650
16	10545	10485	10460	10400	10370
17	10340	10325	10280	10225	10150
18	10135	10100	10030	9970	9890
19	9870	9850	9790	9750	9700
20	9660	9620	9550	9510	9470

FIGURE 3. The perf clusters in the LC-1H (left) well show far less variability within each stage. (Source: C&J Energy Services)

Can refracturing add value in unconventional plays?

In making the case for refracturing, studies show that it has a large potential to add reserves in existing fields at an exceptionally low unit cost.

William Ruhle, Halliburton

Recent advancements in diversion technology and fiber-optic diagnostics have enabled refracturing to become a more predictable and repeatable practice. Halliburton uses a diversion technology that bridges off flow at the fracture face. New completions also are benefiting from this technology in both cemented and uncemented wells, where intra-stage diversion is used to create more transverse fractures per stage than a conventional design would.

Modern refracturing process

Halliburton recently launched a refracturing service that combines subsurface insight with diversion technology and sensor diagnostics. A four-step process is being adopted by operators in multiwell pilot programs. The process involves:

1. Screening the best candidate wells based on both reservoir and completion quality. The company's local technology teams collaborate with operators to quickly and transparently select candidate wells.
2. Designing the optimal refracture treatment to create new fractures and connect existing ones. Each treatment is designed with respect to the initial completion quality. Three-dimensional discrete fracture reservoir modeling can be used to history-match and predict production.
3. Executing the refracturing treatment to ensure full coverage of the pay zone. Simply bullheading a treatment into a well does not provide control of fracture placement and is one reason why some refracks are not fiscally successful. Older wells typically have portions of the reservoir (called pressure sink zones) with higher levels of depletion than the target intervals. The company employs a process called pressure sink mitigation, which forces fluid away from the old fractures to create a more effective distribution of new conductive fractures.
4. Diagnosing the refracturing efficacy to optimize the refrack design for future wells. A diagnostic plan incorporates basic data collection for every well to accelerate the learning curve.

Refracturing opportunities

Each unconventional play has unique motives for refracturing. M. Vincent presented a field study of more than 140 wells in 60 different formations; suggesting there have been successful refracks in every reservoir type, both gas- and oil-bearing formations, including sandstone, shale, limestone, diatomite, conglomerates and coal. This exemplifies the opportunity for operators to rejuvenate production in a variety of assets. Vincent also concluded there have been uneconomic refracks in almost every reservoir type as well. The four-step process Halliburton's clients are adopting helps to narrow the uncertainty and minimize that risk.

The Bakken Formation is an example of an unconventional play with significant opportunity. The average stage count in horizontal wells has more than doubled while the average mass of proppant pumped has increased by 168% since 2008. The progressive change in completions has coincided with a 35% increase in average well productivity in the first year.

Properly engineered refracturing applications have potential for operators who have vintage completions, wells with low completion efficiency, wells that experienced problems during the initial drilling and completion or wells which never had multistage fracturing.

There are varying perceptions about what is technically considered a refracture operation as opposed to a recompletion. By definition, a refracture is a secondary fracture treatment in the same approximate reservoir volume as the initial fracture treatment, typically after an extended period of production. A recompletion is a more holistic description that may include adding pay intervals or installing new tubular in addition to the refrack.

Further sub-categorization is possible:

- A refracture is designed to access underproduced or noncontributing portions of the reservoir. It can be completed with or without a mechanical isolation;
- A reentry is an operation that installs a liner in an existing openhole lateral followed by multistage refracturing; and

- A remediation is a scenario where the primary completion may have experienced a design or mechanical failure. Often, the affected portion of a lateral can be reperforated and refractured to access additional reservoir previously bypassed.

Case studies

Refracturing may simply accelerate the rate of reserves recovery (possibly a fiscal failure at low-interest rates), or it can decrease the decline rate and subsequently increase the recovery factor. Three cases studies from the Bakken Formation exemplify each recompletion sub-category described previously. The production profile has been improved with a shallower decline rate, resulting in incremental EURs. For each of these examples, the operator's original five-year finding and development cost was $20/boe.

A well that was refractured using chemical diverters had an increase in EUR is shown in Figure 1. The EUR increased by 64%. At the date of the refrack there were six wells in the same section with a cumulative production of more than 1 MMboe already extracted.

Figure 2 shows a well that was completed with a 2,591-m (8,500-ft) openhole lateral. Three years later it was reentered to wash and ream the openhole section and install a liner. A multistage refrack treatment was pumped, resulting in a 158% increase in EUR. The capital input is higher in a reentry operation yet still attractive in comparison to the operator's average finding and development cost.

Another well was recompleted with new perforations added and refractured using chemical diverters had an EUR increase of 397 Mboe, or 76%. This yielded an estimated cost of $5/boe.

These case histories provide evidence that refracturing has a large potential for operating companies to add reserves in existing fields at an exceptionally low unit cost. E&P

References available.

Date	2010	2014
Type of Frack Job	28 Stage Treatment	Refrack w/ Diverters
Proppant Mass	2,300,000 lbm	1,400,000 lbm
EUR added	541 Mboe	346 Mboe
Est. F&D Cost	$20/boe	$5/boe

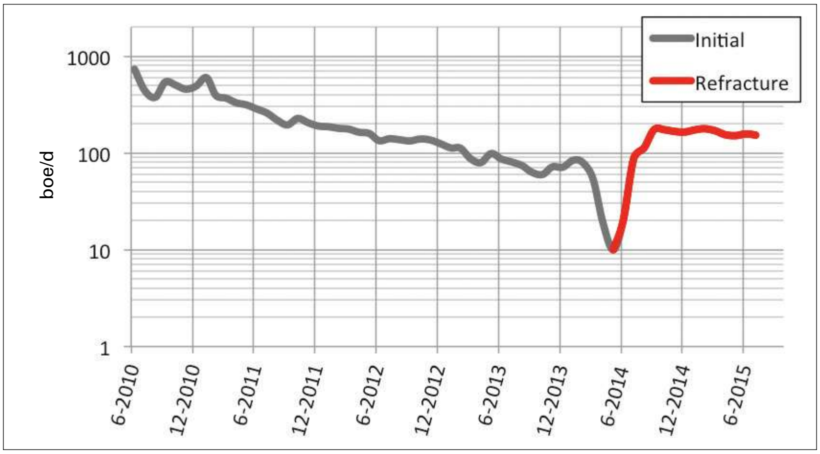


FIGURE 1. Production from a well that was originally completed with 28 stages and then refractured in 2014 displays a 64% increase in EUR. (Source: Halliburton)

Date	2008	2011
Type of Frack Job	Openhole Treatment	20 Stage Treatment
Proppant Mass	516,000 lbm	1,900,000 lbm
EUR added	148 Mboe	233 Mboe
Est. F&D Cost	$20/boe	$12-17/boe

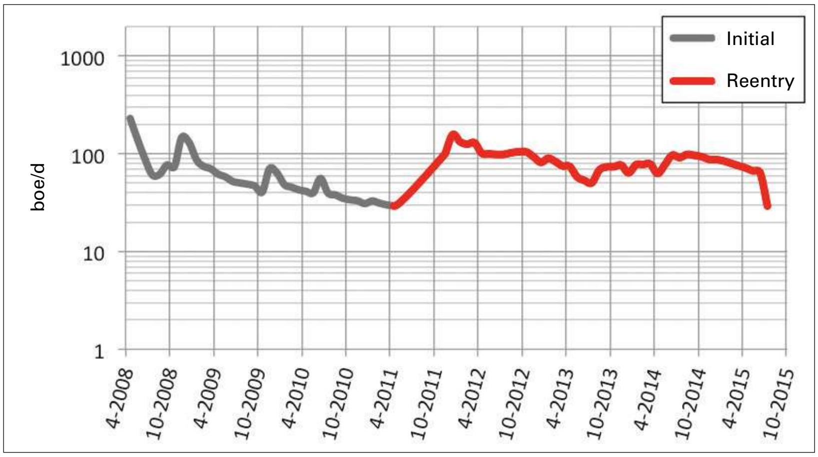


FIGURE 2. Production from a well that was reentered with a liner and then refractured in 2011 shows a 158% increase in EUR. (Source: Halliburton)

Eagle Ford continues to soar

South Texas shale play maintains a steady glide through the market turbulence.

Staff Report

Sprawling some 644 km (400 miles) across the southern and eastern portion of Texas, the Eagle Ford Shale play has kept operators, service companies of all flavors and more than a few restaurants hopping. While activity in the region has slowed due to the market downturn, it has certainly not stopped the explorers and innovators from finding ways to make the play's economics and technologies work in their favor.

At Hart Energy's sixth annual DUG Eagle Ford conference, the lessons learned and techniques that have delivered success were shared by presenters and attendees alike. What follows is a short roundup of those insights gleaned from the conference held in the heart of the Eagle Ford in San Antonio in October.

Halcón's Steve Herod said that lowering drilling and completion costs is essential for companies' survival. Halcón has managed to lower well costs to $6.75 million from $9.5 million in 2014.

Runway extension

Surviving the downturn depends on how far operators can extend their runways. E&Ps are set on regaining altitude—if they have enough running room. Making operations and cash stretch means lowering drilling and completion costs as much as possible. Halcón Resources Corp. has done that in the El Halcón, its East Texas portion of the Eagle Ford in Burleson and Brazos counties, Texas.

Halcón President Steve Herod said that a year ago, the company's Eagle Ford well costs were at $9.5 million. Everything has come down since then: "… pipe, tank batteries, consultants; rope, soap and dope," he said. "So now we are spending about $6.75 million [that includes completed well costs] for a three-string well."

Three-well pad drilling is expected to lower costs more, bringing wells costs in under $6 million on a consistent basis, Herod said.

"We're going into full pad development," he said.

Halcón's drilling group, with more than 100 wells under its belt, continues to work its magic in El Halcón.

"Every time I think our drilling group has hit the max on efficiency improvements, they are able to go a bit further and reduce the spud-to-rig release time another three or four hours," Herod said.

A year ago, DUG Eagle Ford would have been filled with talk about completions: how to space frack clusters and how much sand to use. That's changed.

"Now it's about all these meetings with your bankers," he said. "We've done a lot actually to help extend our runway."

The company's El Halcón Field east of the main Eagle Ford fairway consists of 100,000 net acres and proved reserves of 41.7 MMboe. About one-third of total company volumes come from the Eagle Ford, with the rest of production originating in the Bakken Shale.

Halcón has only one rig running in El Halcón, but the quality of the rock is significant.

"You could put a rig in [Texas A&M's] Kyle Field's end zone and probably make a 1,000-bbl/d well," Herod joked.

Herod knows the area well—he was second in command at Petrohawk Energy Corp. when the Eagle Ford play discovery well was unveiled in La Salle County, Texas, in October 2008. What emerged, the Hawkville Field, set off a surge in drilling from Webb County, Texas, to the Louisiana state line. Petrohawk's assets were subsequently acquired by BHP Billiton.

In 2014 the Eagle Ford was running 216 rigs, according to Baker Hughes Inc. That's fallen about 64% to 77 rigs.

The Eagle Ford is producing about 1.8 MMbbl/d, and the economic impact on Texas has been huge. With the downturn in oil prices, Eagle Ford production is decreasing, with the latest data showing a reduction of about 62 Mbbl/d in September alone, Herod said.

"I have to think this 70 or so rig count is going to be here for a while, and production will come down," Herod said. E&P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Cuttings transport evaluation reduces wellbore instability risks

The automated system tracks hole cleaning efficiency to optimize drilling in longer and more complex wellbores.

Pierrick Ferrando and **Slim Hbaieb**, Schlumberger

In any drilling environment, the removal of drill cuttings from the wellbore is critical for avoiding problems such as bit balling, pack-off and stuck pipe. If left unchecked, these problems can lead to formation damage, loss of circulation and nonproductive time, requiring the driller to pull the drillstring and clean out the well before drilling can continue.

The risks and costs associated with inadequate hole cleaning and wellbore instability are only increasing as operators continue drilling more complex boreholes, including extended-reach wells with long laterals, highly deviated wells, and horizontal and multilateral wells. In deepwater wells, operators are looking to reduce rig time by optimizing their hole cleaning practices and off-bottom circulating time.

Monitoring drill cuttings at the surface is a popular method of determining hole cleaning efficiency and potential borehole stability issues. However, conventional monitoring methodologies are nonautomated, imprecise and do not provide real-time information that the driller requires to perform meaningful quality control and stay ahead of stability challenges downhole.

Automating cuttings analysis

Alleviating these concerns was the motivation behind the development of the Schlumberger CLEAR hole cleaning and wellbore risk reduction service, a real-time monitoring service that evaluates the transport of cuttings at the shale shaker to help the drilling team understand their progress in the well.

The service includes a cuttings flowmeter and weighing tray positioned at the end of each shale shaker, which catches cuttings as they fall off the screen. Cuttings accumulate on the tray and are weighed with strain gauges at predetermined intervals. At the end of each adjustable preset period, the tray swings down to discharge the wet cuttings and then returns to its previous horizontal position to begin collecting cuttings for the next measurement. The device is pneumatically powered by the rig's own air supply and does not interfere with the shale shakers (Figure 1).

Each recorded weight is then sent digitally to an acquisition system, which computes a volumetric flow rate of the cuttings. This measured volumetric rock cuttings flow trend is compared with a theoretical volumetric flow trend calculated from the ROP of the drillbit. These comparisons provide early detection of downhole drilling conditions that might hinder wellbore stability. For example, if the actual volumetric flow is significantly less than the theoretical flow, this indicates inadequate hole cleaning. Conversely, an excess of cutting returns suggests wellbore instability, known as caving or formation damage.

FIGURE 1. The CLEAR hole cleaning and wellbore risk reduction service incorporates a cuttings flowmeter at the end of each shale shaker. The flowmeter catches and weighs cuttings as they fall off the screen but without obscuring access to the shaker. (Source: Schlumberger)

The cuttings flow information is correlated with drilling parameters, cuttings geology, drilling fluid properties and MWD data, all of which are displayed on a real-time data dashboard. The dashboard has a simple, intuitive interface. The data also are transmitted to remote locations for analysis by well construction engineers. The dashboard allows better quality control of the data on the rig and in-depth analysis such that more informed drilling decisions can be made in a timely manner (Figure 2).

The service's ease of use on site and its ability to connect rig crews with support expertise located in corporate offices enable operators to minimize the number of per-

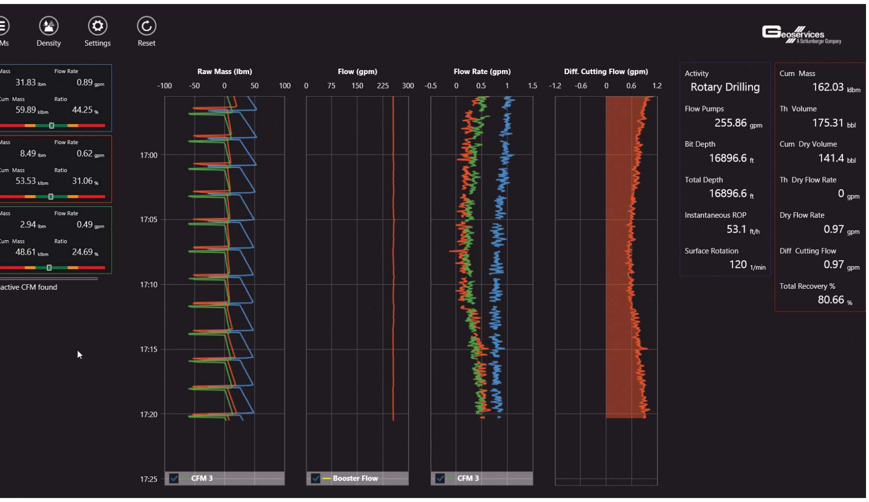

FIGURE 2. Real-time cuttings flow information is accessible through the online dashboard at the rig site or at a remote office. The information is integrated with other MWD data and presented in an easily accessible format, which helps the drilling team quickly assess hole cleaning effectiveness and minimize wellbore instability risks. (Source: Schlumberger)

sonnel on the rig floor, a major driver for reducing health and safety risks. Many times, the same well logging personnel already present at the rig site are used to run this additional service. After just one hour of training on the dashboard, well loggers can confidently operate the system and interpret results without a major time commitment that would distract them from their core responsibilities.

Optimizing drilling

The CLEAR service has been successfully deployed in a number of field scenarios. An operator in the Middle East deployed the service as part of an integrated drilling solution aimed at optimizing the drilling of a sidetrack in one run. This would require reducing the flat time associated with stuck-pipe incidents and wiper trips while maximizing ROP and footage drilled.

Schlumberger engineers recommended running the cuttings surveillance system in conjunction with mud monitoring and a robust rotary steerable system (RSS). The Schlumberger PowerDrive Orbit RSS has a multiaxial component for automatic hold inclination and azimuth capability, which provided additional directional control. The RSS also was proven to reduce drag, improve ROP, decrease sticking risks and deliver superior hole cleaning. A drill fluid expert from M-I SWACO, a Schlumberger company, provided continuous mud monitoring support to the fluid engineer on the rig.

Using this approach, which marked the first time the cuttings surveillance system was used in an integrated service offering, the operator was able to steer the well trajectory into the target zone with low tortuosity and increased ROP. The lateral section was drilled nearly 2.5 days ahead of plan and with minimal stick/slip, shock and vibration. The operator achieved optimal hole cleaning with a cumulative cutting recovery of 84.4% with a 51% reduction in cumulative pill volume.

The service also helped deliver a new field record for drilling a 6⅛-in. section with a standalone RSS. The operation's average ROP was 28 m/hr (91 ft/hr), while previous jobs averaged 22 m/hr (72 ft/hr). Footage increased to 603 m/d (1,978 ft/d) compared with the previous record of 429 m/d (1,409 ft/d). The operator also reduced connection time by 60% toward the end of run, thus saving $148,000 in its authorization for expenditures spend.

Assuring wellbore stability

An operator in Southeast Asia deployed the hole cleaning service with an aim of mitigating anticipated wellbore instability challenges during a three-well extended-reach drilling operation. The operator needed to monitor and optimize its hole cleaning strategy while drilling 12¼-in. by 13½-in. sections at 70 degrees with an average departure greater than 1,524 m (5,000 ft).

The information provided by the CLEAR service indicated that the drilling fluid rheology was inefficient at lifting the cuttings to surface. The drilling team used this insight to raise the low-end fluid rheology, thus improving hole cleaning and avoiding the need for unplanned circulation.

Using the new service, the drilling team was able to enhance its pill strategy. Fewer pills were deployed with no detrimental impact on hole cleaning, which increased the net ROP and decreased the time spent on mud treatment. The size, frequency and type of pills used also were revised, which ultimately optimized efficiency and control time dedicated for a secondary hole cleaning. High-viscosity pills were maintained for the larger outer-diameter (OD) slant hole, and tandem pills were assessed and measured as having optimal performance in smaller ODs.

The solution led to an overall improvement in drilling performance and gave the operator greater confidence to drill faster. The average time spent per stand for circulating and pumping pills decreased by 11 minutes compared with previous wellbores. In total, the systematic approach saved the operator 16 hours of rig time and $194,000 in direct costs. E&P

Protecting upstream assets through sand monitoring

Wireless corrosion and sand monitoring probe delivers real-time information to operators.

Fiona Butters, Emerson Process Management, and **Richard Munro**, Stork

As E&P companies battle against lower margins and a weak oil price, the cost-effective flow of hydrocarbons from reservoir to refinery has never been more important.

Yet one of the most significant threats to production today is that of sand erosion. All too often sand can clog production equipment, erode completion components and interfere with oil and gas infrastructure. Together, these can have a highly negative effect on production rates from the field.

The increase in aging oil and gas assets also has led to a renewed focus on sand monitoring. Such fields often have rising water production and more sand as well as increasing amounts of gas, leading to higher velocities and a greater risk of erosion damage from sand particles. Furthermore, with the need to make smaller fields more economically viable, predictive sand monitoring tools are crucial to ensure maximum returns from these fields' production systems.

It's against this backdrop that the monitoring of erosion on essential lines is vital as sand contributes to the failure of equipment and loss of containment as well as posing a risk to personnel and the environment. Operators today need access to a complete production system, delivering intelligent real-time information and operating alongside existing instrumentation. Are today's sand monitoring systems rising to these challenges?

Evolution of sand monitoring technologies

The last few years have seen the emergence of acoustics and erosion-based sand sensors as a means of providing immediate and accurate responses to sand erosion. Such acoustic sensors use the acoustic energy generated by sand particles to calculate sand production in multiphase pipeline flows.

Many erosion-based sand monitoring technologies today also are based on the electrical resistance principle, where metal loss on the element is measured as increased electrical resistance in a sensing element exposed to sand erosion. Sand production rates can then be quantified by combining measured metal loss rates with average sand particle size and flow data.

Acoustic and erosion-based sand monitoring systems complement each other well. Acoustic monitors provide an immediate response to sand production. They are, however, complemented by intrusive sand/erosion probes that generate accumulated erosion data and are able to provide highly accurate measurements of the accumulated long-term effect of sands.

In addition, the field signature method, which measures corrosion or erosion directly on the pipe wall by detecting small changes in current flow due to metal loss, also can operate alongside sand monitoring.

Integrated wireless-based solution

For all these technology developments, however, there still remains a lack of integration across asset integrity management systems and a need to adopt ever more innovative digital and wireless-based technologies.

It's for this reason that Emerson recently introduced the Roxar CorrLog and SandLog Wireless transmitters. The transmitters can be directly integrated within

Wireless corrosion and sand monitoring probes allow continuous online monitoring. (Source: Emerson Process Management)


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WirelessHART networks, a wireless sensor networking technology, to provide a complete asset integrity management system for operators. They are examples of how Emerson's automation, digital and smart wireless technologies can be combined with its Roxar corrosion and sand monitoring instrumentation to protect operators' upstream and downstream assets.

The operating principles of the new probe are based on the already described electrical resistance corrosion probe technique, which relies on the erosive effects of sand particles on thin noncorrosive elements mounted on a probe inserted into the pipe. When combining measured sand/erosion rates with flow rates and assumed sand particle size, sand production can be quantified.

In this case, however, the transmitters are wireless-based, resulting in a significant reduction in installation costs compared to wired online systems and also allowing continuous online monitoring in previously inaccessible areas.

The system includes an up to 20-m (66-ft) cable between probe and transmitter. In this way, the system can be installed where it is most convenient for the user (in regard to maintenance and battery replacement, for example) as well as where it is most beneficial for wireless signal routing, thereby avoiding shadows where radio communications might be difficult.

The transmitters are also highly accurate and reliable and come with a low risk of signal loss in high-risk applications, with the sensitive sensors generating improved information for asset protection. Multielement sand/erosion probes also are incorporated within the Roxar SandLog transmitter to provide increased accuracy.

The raw data also can be transmitted to the Roxar Fieldwatch system for further analysis and verification. Through its flexible, scalable and distributed architecture, the Fieldwatch software combines real-time data with efficient online analysis and condition monitoring, allowing the user to have greater confidence in the veracity of the production data.

Probes from other manufacturers also can be read, and the direct transmission of metal loss values can be fed into Fieldwatch for improved monitoring and analysis. The transmitters also can be combined with any other Emerson WirelessHART products as they use the same gateway for data communications.

The result is a complete asset integrity system with direct integration to the WirelessHART network.

Industry collaboration

Stork, a global provider of knowledge-based asset integrity services, has recently successfully installed this

Monitoring of corrosion and sand erosion during production is a critical production operation.

sand-erosion monitoring solution on a major North Sea operator's platform. The wireless devices will provide flexible, cost-effective and highly accurate online monitoring of sand erosion from the field in question, helping to extend equipment life and increase production from reserves.

The collaboration between Emerson and Stork also marks the first installation of the Roxar SandLog wireless monitors in the U.K. Continental Shelf and combines Stork's monitoring solutions service offering alongside Emerson's sand-erosion monitoring system.

Stork's monitoring solutions department is positioned to deliver a range of traditional and advanced techniques for monitoring the rate of corrosion, erosion, stress, temperature, strain or intrusion on pipelines both on and offshore.

Stork's monitoring solutions team provides operators with the means to monitor the rate of erosion on their assets, identifying and continuously reporting on areas of concern and enabling the planning of effective remedial action.

Increased control, insight

As operators look to deliver on the bottom line, incorporating greater intelligence and integration into their production and sand monitoring systems is becoming an even more pressing issue.

With highly sensitive and accurate sensors and direct integration to a wireless network and through the close collaboration between Stork and Emerson, it's encouraging to see sand erosion monitoring technologies delivering greater insight and control over production operations. E&P

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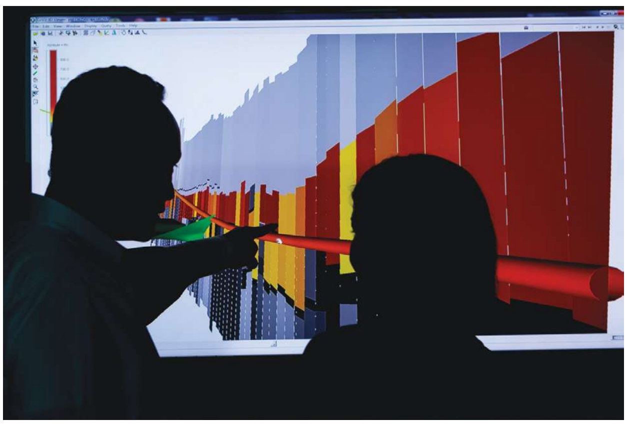
[1] Magic Quadrant for Business Intelligence and Analytics Platforms.
[2] IDC Worldwide Business Analytics 2014 – 2018 Forecast.

Geospatial navigation, analysis service provides real-time 360-degree view

Baker Hughes has released its VisiTrak geospatial navigation and analysis LWD service. This LWD service combines advanced prewell modeling, deep-reading LWD sensors, proprietary visualization software and precise reservoir navigation to improve efficiency in well construction and facilitate optimal well placement for increased hydrocarbon recovery, a product announcement stated. The VisiTrak LWD service simplifies prewell planning and logistics with interpretation capabilities for complex geological scenarios, facilitating accurate prewell models and well designs without the need to drill costly pilot holes. While drilling, extended-depth LWD readings determine the distance to and angle of adjacent bed boundaries to visualize complex reservoir architecture in real time up to 30 m (100 ft) from the wellbore in every direction. In comparison, conventional LWD tools are typically limited to less than 6 m (20 ft). The combination of early detection and advanced visualization allows operators to precisely and efficiently navigate to and through the reservoir's most productive zones to improve ultimate recovery. *bakerhughes.com*



The VisiTrak geospatial navigation and analysis LWD service is the latest example of Baker Hughes' strategy to improve well efficiency, optimize production and increase ultimate recovery. (Source: Baker Hughes)

Flying node system advances deepwater OBS

Autonomous Robotics is developing a flying node system that operates as a swarm of AUVs for recording ocean-bottom seismic (OBS) data, the company said in a press release. This technology has the potential to hugely disrupt the offshore seismic market. OBS surveys record very high-quality data especially suitable for field appraisal and development. Unfortunately, the cost of gathering such seismic data at extreme depths in complicated geology remains high. Using the flying node system, the company predicts a tenfold increase in the deployment and recovery rates compared to ROV-deployed nodes, which should help to substantially reduce this cost. The planned system foresees the deployment of 3,500 flying nodes from a vessel, which then descend (fly) to a predetermined position on the seabed. The flying nodes are accurately positioned on the seabed using an ultrashort baseline acoustic navigation system mounted on an unmanned surface vessel, allowing both 3-D (exploration) and 4-D (production/life-of-field) seismic. The nodes will have the ability to remain on the seabed recording data for up to 60 days to cover a wide range of survey requirements. *autonomousroboticsltd.com*

Inert tracer technology optimizes sand-stimulated completions

CARBO Ceramics Inc. has released CARBONRT ULTRA, a new easily detectable inert tracer technology for sand-stimulated completions in vertical and horizontal wells, a release stated. CARBONRT ULTRA enables the detection and evaluation of near-wellbore proppant location and quantity. This evaluation provides an accurate measurement of perforation cluster efficiency and near-wellbore connectivity to maximize ultimate recovery. Understanding proppant placement also supports the optimization of stage placement and proppant diversion. Information gathered from these diagnostics enables operators to reduce costs and ultimately improve their completions efficiency, the company said. CARBONRT ULTRA proppant technology is detectable with a standard neutron logging tool. The tracer does not dissolve or wash away and is permanently identifiable, providing operators the flexibility to conduct post-fracture logging months or years after fracturing. CARBONRT ULTRA is blended at an engineered ratio with sand prior to or during pumping operations. *carboceramics.com*

Underwater positioning solution designed for seabed seismic acquisition

Sercel has released GeoTag, the acoustic positioning solution for seabed seismic acquisition. GeoTag can be used to accurately position all types of ocean-bottom cable (OBC), ocean-bottom node and transition zone cable systems for seabed seismic surveys in water depths down to 500 m (1,640 ft), a press release stated. The highly flexible and reliable GeoTag product operates with the smallest acoustic positioning transponder available on the market. The transponders are attached to the seabed seismic equipment and interrogated by a vessel-based transceiver. GeoTag's design allows rapid maintenance such

GeoTag is fully scalable for use by crews deploying up to 10,000 acoustic positioning devices. (Source: CGG)

as battery replacement for improved crew efficiency. The transponders also can be stored on a reel and deployed mechanically when used with OBC systems for seamless and cost-effective operations. With the addition of GeoTag's acoustic positioning capability, Sercel now offers a complete acquisition solution for a wide range of seabed seismic surveys. GeoTag is fully scalable for use on small to large seabed crews deploying up to 10,000 acoustic positioning devices. *cgg.com*

Valve cages help prevent injuries while servicing compressor valves

Zahroof Valves Inc. (ZVI) has released the ZVI Valve Cage-Integral and ZVI Valve Cage-Removable. The lighter ZVI Valve Cage assembly is designed to be safer and easier to install and remove than conventional valve and cage assemblies, especially for larger discharge valves, according to a product announcement. The ZVI valve cages have a better flow path for gas, with larger rounded ports that can be directly fastened to the ZVI valve. Made of corrosion-resistant steel similar to the valve body itself, the cage will not corrode under normal conditions and is easily repairable, reducing unnecessary costs, the company said. The ZVI Valve Cage-Integral features a ZVI StraightFlo (SF) Valve with a cage that does not need to be removed from the valve during servicing, installation or removal of the valve from the cylinder. Available for valves of all sizes, the ZVI cage's height can be easily modified to accommodate spacers or new valves. The ZVI Valve Cage-Removable can be used with a ZVI SF Valve or with conventional valves. In the case of an existing SF Valve, it can be directly fastened to the valve, making installation and removal of the valve safer and easier without the need of special tools. *zahroofvalves.com*

New valve cages reduce injuries to workers when changing valves. (Source: Zahroof Valves Inc.)

Slow-release long-lasting inhibitors prevent scale, corrosion

U.S. Water has released its new ScaleGone and ScaleGone CI, a long-lasting slow-release solid scale inhibitor (SI) and combined SI/corrosion inhibitor (CI) for hydraulic fracturing fluids as well as for use in producing wells, the company said. ScaleGone solid SI particles, which measure the same size as proppant, can be introduced during stimulation treatment, ensuring distribution throughout the well fracture. Safe to use with other stimulation products, ScaleGone slowly releases into produced fluids. In addition, ScaleGone can be introduced into already producing wells. ScaleGone and ScaleGone CI provide long-lasting scale and corrosion protection, up to several years depending on loading. These products can prevent deposition in the wellbore area and the tubing just as powerfully as they do at the formation face to prevent scale and costly production problems. *uswaterservices.com*

Circulation sub maximizes efficiency of deepwater operations

Weatherford International Plc has released its JetStream Radio Frequency Identification (RFID) circulation sub, a release stated. Poor wellbore integrity can cause events such as stuck pipe, wellbore collapse, sloughing shales and lost circulation, which are major concerns for drillers in deep water. The JetStream RFID circulation sub enables operators to run a series of tools at different positions along the drillstring and remotely actuate the valves an unlimited number of times in a single trip to achieve higher flow rates and cleaner wellbores. "As operators deal with more complex wellbores, the ability to drop an RFID tag from the surface and circulate it through the sub enables our clients to open and close downhole tools multiple times, which provides superior operational flexibility and saves days of rig time. In deepwater drilling operations, RFID technology can save the client over $1 million per application by reducing the amount of nonproductive time. This is critical in the current economic environment," said Neil Gordon, vice president of intervention services and drilling tools at Weatherford. *weatherford.com/jetstream* E&P

The JetStream drilling circulation sub gives operators the freedom to selectively actuate any valve in a string of RFID-compatible tools. (Source: Weatherford)

Gulf players embrace EOR while tightening grip on costs

The Middle East's big national oil companies are focused at the project level.

Mark Thomas, Editor-in-Chief

While the strategic chess game of global oil and gas supply goes on at the macro-level between OPEC and nonOPEC players, at the project level the Middle East's producers are painfully aware of their own very real need to reduce their costs.

Present estimates by OPEC for the region's conventional oil reserves are put at 796 Bbbl, nearly half the global total of recoverable crude, while its gas reserves are also almost equally abundant, representing more than 40% of the world's total.

But this doesn't exclude the region from feeling some pain due to the oil price slump that has decimated the global industry since late 2014. Saudi Arabia, for one, has seen its credit rating cut by various agencies as the price decline hits its national revenues (derived 80% from energy exports), with its public debt to possibly increase to up to 50% of its GDP within the next five years.

Then again, this doesn't seem to have particularly worried King Salman bin Abdulaziz al-Saud who, after acceding to the throne in January 2015, announced one-time bonuses for public sector workers. It's also worth pointing out that even if the kingdom's GDP did rise to 50%, the figure would still be well below that of most Western economies.

The LR5 rig is on one of the world's largest unconventional gas resources, the Khazzan Field in Block 61 onshore Oman, where operator BP will drill horizontal wells and use hydraulic fracturing to stimulate production from the tight gas reservoir. (Source: BP)

Long term

State-owned Saudi Aramco also is increasingly assured about its long-term place in the world. Its chairman, Khalid al-Falih, confirmed in early November that the company had no plans to cut oil production and that he foresees a rebalancing of the oil market in 2016, according to an interview in the *Financial Times* newspaper.

He described $100/bbl oil as having been a "free-of-charge insurance policy" provided by Saudi Arabia that had allowed shale and deepwater producers to flourish. However, that policy "does not exist anymore," he said.

The United Arab Emirates (UAE) also is pushing on with its plans to increase crude output while at the same time looking to take advantage of market conditions to bring down its opex by a set target of 25%, according to Ali Khalifa al-Shamsi, Abu Dhabi National Oil Co.'s (ADNOC's) strategy and coordination director. Speaking at a press briefing ahead of the Abu Dhabi International Petroleum Exhibition and Conference (ADIPEC), he said the company is making good progress toward achieving that figure.

His message was backed up by UAE Minister of Energy Suhail Al Mazrouei, who stressed in an official statement ahead of ADIPEC that its national oil companies would continue to "seek to reduce production cost by increasing the efficiency of their operations."

Pipelaying takes place offshore Qatar connecting the North Field to the Qatargas LNG facility at Ras Laffan as part of Qatar Petroleum and Shell's Qatargas 4 LNG project. (Source: Shell)

Fall in spending

Aside from looking to renegotiate with contractors for lower prices by anywhere between a widely reported 10% to 25% for services across the spectrum of their upstream and downstream operations, the majority of the Middle East's operators are—like many of their Western counterparts—also likely to simply delay nonessential maintenance work on their existing projects to keep a tighter control on spending.

In terms of capex on new field developments or projects in the process of development, analyst Infield Systems said capex is expected to slow. Although capex will continue to be driven by Iran, Qatar and Abu Dhabi over the period, with several capital-intensive projects under development, it said that as developments such as various South Pars phases offshore Iran come to a close, overall capex will fall by 17% between 2016 and 2017.

Enhanced recovery focus

The region's interest in enhanced recovery technologies continues to be one of the main emerging themes generating fresh activity. The latest example of this came from ADNOC and Germany's Wintershall, which confirmed at ADIPEC that they had signed a memorandum of understanding regarding future cooperation in R&D activities.

This will specifically focus on EOR using specialized chemicals, or "cEOR," as they dubbed it, with the aim of jointly developing solutions to meet typical subsurface challenges presented by the emirate's oil fields—high temperature and high salinity in carbonate reservoirs.

A pilot test is in the pipeline, said the companies, with the memorandum of understanding's aim being to help Abu Dhabi on its way toward its publicly stated eventual target of 70% ultimate recovery from its fields.

Another EOR project taking place in Saudi Arabia is the kingdom's first carbon capture and storage pilot project, underway on the world's biggest oil field, Ghawar. If successful, according to oil minister Ali al-Naimi, it could boost recovery rates by up to 20%.

Ghawar, which has been pumping crude since 1951, incredibly still produces more than 5 MMbbl/d of oil as well as 70.7 MMcm/d (2.5 Bcf/d) of gas.

Saudi Aramco's carbon project got underway earlier this year after first being hatched in 2011. About 1.1 MMcm/d (40 MMcf/d) of CO_2 will be captured at the Hawiyah gas recovery plant and piped to the Uthmaniyah area for injection into the oil reservoirs. The aim once more is to raise the field's recovery factor

A worker on top of a loaded pipe barge, with the cargo destined to connect the giant North Field offshore Qatar to the world-class Qatargas LNG facility at Ras Laffan for onward export to international markets, is shown. Gas via the Dolphin pipeline also flows directly to the UAE, which is now looking to develop its tight gas fields to meet increasing domestic demand. (Source: Shell) from its current given figure of 50% to 70%, which on a field of Ghawar's scale is a huge increase in recoverable reserves. It currently has estimated remaining proven oil reserves of 75 Bbbl, according to the U.S. Department of Energy.

Sour gas

Shell is another major partner with Abu Dhabi, where it is underway with its 30-year joint venture with ADNOC on the onshore Bab sour gas development, signed in 2013.

Bab is a challenging reservoir because of its high concentration of hydrogen sulfide and CO_2, but the companies are well underway with technical studies after completing a pre-FEED study earlier this year. A full FEED study is expected to get underway during 2016, with the project definitely world-class if it proceeds to sanction—estimates put forecast capex at about $11 billion, with an onstream date expected near 2020 with production of up to 28 MMcm/d (1 Bcf/d) for local use.

Despite the global fall in energy prices, this project is progressing to schedule with no sign of potential delay, particularly as gas remains in big demand in Abu Dhabi, which currently imports it from Qatar through the Dolphin pipeline mainly for electricity generation and desalinating seawater.

Meanwhile, BP's Khazzan tight gas field development in Oman is progressing to schedule, with first gas due in late 2017. More than 45% of the project and infrastructure work has been completed so far, with seven drilling rigs currently on the field and 12 wells drilled so far. Sixteen will be drilled by year-end 2015, with nine rigs planned to be operational by then.

The full field development of Khazzan will see about 300 wells drilled over a period of 15 years. The central processing facility will include two 14-MMcm/d (494-MMcf/d) process trains. The project will increase the country's gas supply by one-third, with up to 28 MMcm/d of gas expected to flow. BP operates Block 61 with a 60% interest, with Oman Oil Co. Exploration and Production holding the remainder. E&P

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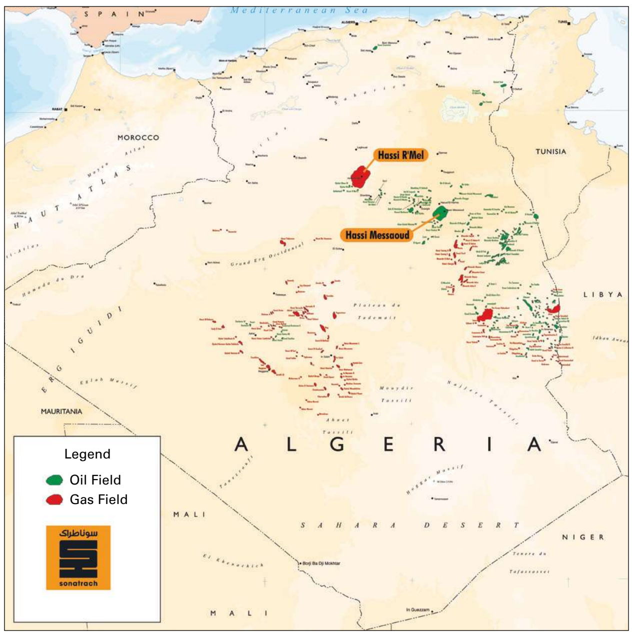
Hassi R'Mel Field feeds initial commercial LNG industry

The first delivery of LNG to the U.K. in 1964 from Algeria marked the start of the commercial LNG industry.

Scott Weeden, Senior Editor, Drilling

Eight years after the Hassi R'Mel Field was discovered, Algeria began commercial production of LNG with deliveries to Europe. The field supplies natural gas to LNG plants at Arzew and Skikda as well as four export pipelines to Europe—Medgaz, Trans-Mediterranean, Maghreb-Europe and Galsi.



The Hassi R'Mel Field is one of the largest gas fields in the world. It supplies LNG plants at Arzew and Skikda. (Source: Sonatrach)

The giant Hassi R'Mel gas field was discovered in 1956 along with the giant Hassi Messaoud oil field. Gas production started in 1961. It is the largest gas field in Algeria and one of the largest gas fields in the world, with annual production of about 100 Bcm (3.5 Tcf). The field has estimated reserves of 2.4 Tcm (85 Tcf) of gas and probable reserves between 2.7 Tcm and 3 Tcm (95.3 Tcf and 106 Tcf). The areal extent of the field is about 70 km (43 miles) from north to south and 50 km (31 miles) from east to west.

The field is located near the village of Hassi R'Mel, which is 550 km (340 miles) south of Algiers.

Hassi R'Mel is a Triassic gas field, which was discovered by the HR-1 well. The field is in a Cretaceous anticline of the M'zab dorsal structure, which separates the Western Org Paleozoic Basin from the Oued Mya Basin to the east.

Geologically, Cambrian rhyolite forms the basement. It is overlain by the Tassili Cambro-Ordivician sandstone group, a Siluro-Devonian shale and Mesozoic sediments. The A, B and C reservoir sandstones are Permo-Triassic and about 115 m (377 ft) thick, which are sealed by Late Triassic salt and shale.

In 1964 Algeria officially launched the first LNG complex at Arzew called Camel (GL4Z), which was capable of processing 1.8 Bcm/year (63.5 Bcf/year). That was followed in 1972 with the opening of the Skikda LNG plant (GL1K). The LNG plant had a production capacity of 6.5 MMcm/year (229 MMcf/year) of LNG, 170,000 mt/year of ethane, 108,400 mt/year of propane, 92,600 mt/year of butane and 60,250 mt/year of natural gasoline, according to Sonatrach's history.

The Hassi R'Mel Module 1, with a production capacity of 18 Bcm/year (635 Bcf/year) of gas and 3 MMmt/year of condensate, started in 1978. Another LNG plant at Arzew also was brought into service with a production capacity of 17.5 MMcm/year (618 MMcf/year) of LNG.

Two more modules began production in the field in 1979, each with a production capacity of 20 Bcm/year (706 Bcf/year) of gas, 4 MMmt/year of condensate and 880,000 mt/year of LPG.

There are four LNG complexes, three in Arzew and one in Skikda, with a full production capacity of 44 Bcm/year (1.5 Tcf/year) of LNG along with two LPG complexes in Arzew, with a full production capacity of 10.4 MMmt/year. Since then the LNG complex GL4/Z, previously known as Camel, was shut down in April 2010. New LNG plants are under construction at Arzew and Skikda, according to Sonatrach. E&P

Drilling for clues

From near or far, the *JOIDES Resolution (JR)* looks like any ol' drillship. She has a derrick and pipe rack, a logging shack and helipad. She even has a doghouse and a rathole. Yes, the *JR* is well and truly a drilling rig that floats, and she has been investigating the Earth's origin and evolution through scientific ocean coring worldwide. For those lucky scientists selected to sail onboard her for two months out of their year, the *JR* is both home and research laboratory.

Launched as *SEDCO/BP 471* as an oil exploration vessel, the riserless *JR* was converted for scientific use and began working for the Ocean Drilling Program (ODP) in January 1985 as the successor of the *Glomar Challenger*. Drilling with the ODP continued until September 2003, at which point the Integrated Ocean Drilling Program (IODP) began. After extensive modernization in Singapore in 2007 to 2008, the vessel resumed operations for the IODP in 2009. In October 2013 the IODP transitioned to the International Ocean Discovery Program.

During her ODP and IODP years, vessel operations extended from north of the Arctic Circle to south of the Antarctic Circle and from the depths of the Marianas Trench to the coastal areas off New Jersey, according to an IODP fact sheet.

Ocean drilling has confirmed the theories of plate tectonics and continental drift, discovered gas hydrates in sediments below the ocean and confirmed that they exist worldwide, and provided insights into the paleoclimate record over the past 100 million years and more.

During normal operations, work aboard the ship never ceases as drilling and science activities continue 24 hours a day. A typical ship's complement consists of up to 60 scientists and technicians and 70 crew members, the fact sheet noted. About 1,672 sq m (18,000 sq ft) of space onboard the vessel is reserved for scientific operations, including analyses of core samples for geological, physical, chemical and microbiological research. More than 736 cu. m (26,000 cf) of space is used for refrigerated storage of the cores.

To learn more about shipboard activities, visit *joidesresolution.org*. E&P

Vessel Facts	
Sector:	Scientific research
Owner:	Overseas Drilling Ltd., subsidiary of Siem Offshore AS
Constructed at:	Halifax, Nova Scotia, Canada
Last Upgrade:	2009, Jurong Shipyard, Singapore
Launched:	1978
Size (length, breadth):	143.4 m (470.5 ft), 21.3 m (70 ft)
Gross Tonnage:	10,282 st
Net Tonnage:	3,084 st
Transit Speed:	10.5 knots
Water depth (maximum, minimum):	8,230 m (27,000 ft), 91 m (300 ft)
Operating Arena:	Worldwide
Classification:	ABS A1 E Drilling Unit AMS ACCU
Ice Class:	1B
Accommodation:	129 persons

The *JOIDES Resolution* departs Honolulu, Hawaii, May 9, 2009, at the beginning of Expedition 321: Pacific Equatorial Age Transect 2. (Source: William Crawford, IODP/TAMU)

AFRICA

Eni makes gas, condensate discovery offshore Congo

Eni discovered gas and condensate offshore Congo in the exploration prospect of Nkala Marine, the company said in a news release. The prospect is located in the presalt Marine XII Block, about 20 km (12 miles) from the coast and 3 km (1.9 miles) from the Nene Marine Field, already in production. The find is expected to have a potential of 250 MMboe to 350 MMboe in place. During the production test, the well provided more than 300,000 scu. m/d (10.5 MMscf/d) of gas and associated condensate. The well, drilled in a water depth of 38 m (125 ft), encountered a major gas and condensate buildup in the presalt clastic geological sequence of lower Cretaceous age, crossing a hydrocarbon column of 240 m (787 ft). Eni estimates the resources in place of oil and gas discoveries made in the Eni-operated Marine XII Block to be about 5.8 Bboe. The production of the block, started last December, stands at about 15,000 boe/d. Additionally, the company reported it will restart an aggressive exploration campaign once crude prices rise to $70 dollars a barrel, a Reuters report stated. The company, which recently discovered the super-giant Zohr Field offshore Egypt, had an estimated 6 Bboe of resources in about 600 undrilled prospects in its key African region.

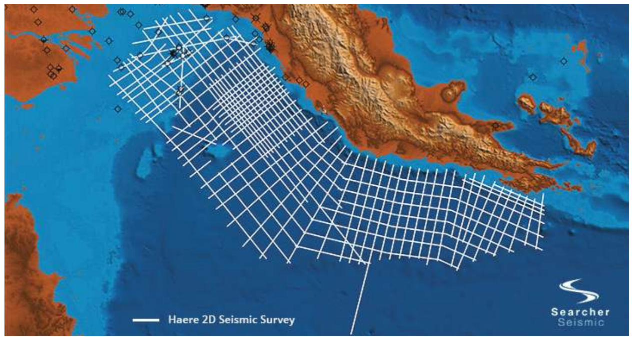
Egypt's president approves $2.2 billion in exploration contracts

Egypt's President Abdel Fattah al-Sisi approved six new oil and gas exploration contracts for investments worth at least $2.2 billion, the Oil Ministry said, according to a Reuters report. The agreements include the search for oil and gas in the Mediterranean, Nile Delta, Western Desert and the Gulf of Suez. The deals were initially mooted at an investment conference in Sharm El Sheikh earlier this year.

ASIA

Searcher gears up for seismic survey over Gulf of Papua

Searcher Seismic is working to acquire about 17,000 km (10,563 miles) of 2-D long-offset high-resolution broadband seismic data over the Gulf of Papua, the company said in a news release. BGP is a partner in the project, which is being conducted in cooperation with the Department of Petroleum and Energy. The *BGP Explorer* has now mobilized for the project. The Haere survey is a grid of modern high-quality data that will be fundamental in assisting the reinterpretation of the geology in the Gulf of Papua and the identification of prospective structural and stratigraphic trends that can be used for regional evaluations and future detailed seismic survey designs, said Rachel Masters, Searcher's global sales manager. The new survey brings Searcher's total data library in the Gulf of Papua to 58,000 km (36,039 miles). Fast-track data deliveries will commence in first-quarter 2016.



Haere is a grid of modern high-quality data. (Source: Searcher Seismic)

Lundin makes small gas find offshore Malaysia

Lundin Malaysia BV has made a small gas discovery with the Mengkuang-1 exploration well in license PM307 offshore Malaysia, a news release stated. The well targeted hydrocarbons in Miocene-aged sands located 75 km (47 miles) northwest of the Bertam Field operated by Lundin Malaysia. Mengkuang-1 was drilled with the West Prospero jackup rig to a total depth of 1,259 m (4,131 ft) below mean sea level. The well encountered 9 m (30 ft) of gas pay in the I-35 group Miocene channel sands. The well was plugged and abandoned. Lundin Malaysia holds 75% working interest in PM307, and partner Petronas Carigali Sdn Bhd holds 25%.

AUSTRALIA

SBM Offshore wins contract for Browse FLNG turret FEED

Technip SA awarded SBM Offshore a FEED contract for three large-scale turret mooring systems associated with the proposed Browse Floating LNG (FLNG) development in Australia, SBM Offshore said in a news release. The three turrets are expected to be designs similar to and slightly larger in size than the Shell Prelude FLNG turret that SBM Offshore was awarded in 2011. Integration with the Prelude facility in Korea is currently ongoing. The proposed Browse project, operated by Woodside Energy Ltd., is located 425 km (264 miles) north of Broome in Western Australia. The project's reference case is based on three FLNG facilities to develop the Brecknock, Calliance and Torosa fields in the Browse Basin and is subject to a final investment decision targeted for the end of the FEED in second-half 2016.

DNV GL wins contract for Ichthys LNG project

DNV GL has secured a contract to provide in-service verification and classification services to a range of facilities at the Ichthys LNG project in Australia, according to a news release. INPEX is preparing to transition from the project execution phase to the operational phase of the megaproject. Operations are scheduled to begin in 2017. The primary scope of work includes in-service verification of the Ichthys facilities, the central processing facility (CPF), FPSO, subsea production system, gas export pipeline, onshore combined cycle power plant and onshore LNG plant. DNV GL also will provide in-service classification of the CPF and the FPSO hulls. DNV GL has provided vendor inspection, verification and offshore classification support to the $34 billion venture since 2012. Located 220 km (137 miles) offshore Western Australia, the Ichthys Field sits on Block WA-285-P in the Browse Basin in the Timor Sea. This gas and condensate field lies at a water depth of 250 m (820 ft) and represents the largest discovery of hydrocarbon liquids in Australia in 40 years, according to the release.

EUROPE

CGG may cut 25% of staff in new restructuring

CGG SA released a new restructuring plan to begin next year that could see the French seismic survey group reduce its workforce by 25%, the CGT union said, according to Reuters. CGG declined to comment. CGG is already cutting 2,000 jobs over two years to reduce the workforce to 7,700 people by year-end 2015 in response to the sharp drop in the price of crude.

Deepwater gas field discovered offshore Romania

Lukoil, PanAtlantic Petroleum Ltd. and Romgaz discovered a large deepwater gas field offshore Romania, a press release stated. The field is in the Trident Block (EX-30). It was discovered after the exploratory Lira 1X well was recently drilled. Lukoil Overseas Atash BV is operator, and there is a concession agreement with the Romanian government that was finalized. Romgaz's share in the project is 10%, Lukoil's is 72% and PanAtlantic Petroleum Ltd.'s is 18%. Water depth in the block ranges from 300 m to 1,200 m (984 ft to 3,978 ft). The Lira-1X well is about 170 km (106 miles) from the coast. It was drilled to a 2,700-m (8,860-ft) total depth by the Transocean *Development Driller II* semisubmersible rig. The well was temporarily abandoned for further evaluation of the Lira gas discovery. Seismic data indicated that the gas field's area can reach up to 39 sq km (15 sq miles) with estimated natural gas reserves of 30 Bcm (1 Tcf). In 2016, an exploration well will be drilled at Lira and seismic data reprocessed to confirm the size of the discovery and assess potential hydrocarbon reserves.

Market conditions prompt more job cuts for Maersk Oil

Maersk Oil plans to shed between 10% and 12% of its global workforce in an effort to reduce operating costs by 20% by year-end 2016, the company said. The move, which also impacts employees in contractor roles and at the company's headquarters, follows an extensive internal review of business activities and continued low oil prices. It brings the total number of positions taken out of the organization during 2015 to about 1,250.

RUSSIA

Russian state agency ready to sell off Rosneft stake

Russia's state property management agency is ready to sell off stakes in several major firms as part of a privatization plan if President Vladimir Putin backs the idea, Agency Head Olga Dergunova said, according to a Reuters report. The agency is ready to sell stakes in oil giant Rosneft, hydropower company Rushydro, diamond producer Alrosa and airline Aeroflot, Dergunova said. The government has recently recommended the agency speed up large asset sales irrespective of market conditions, she added.

SOUTH AMERICA

Colombia will cut oil taxes to boost offshore exploration

Colombia will lower tax rates for oil companies drilling in some offshore Caribbean blocks, the Mines and Energy Minister said, in an effort to encourage exploration amid a global slump in crude prices, Reuters reported. Contracts for various offshore blocks will get a 25% discount on income taxes and will be exempt from value-added tax and customs charges. The move will help keep output near 1 MMbbl/d in the medium term. Colombia's public finances have been battered by the fall in prices for crude oil, its biggest export and source of foreign exchange. The Andean country produced an average of 1 MMbbl/d of crude in September. State-run Ecopetrol produces more than half of Colombia's oil, while the Canada-based Pacific Exploration and Production Corp. is the biggest private player. The government hopes to increase investment in the sector to about $15 billion per year from current levels of between $5 billion and $7 billion. E&P

PEOPLE

Patrick McCarthy is the new CEO of ProSep replacing **Neil Poxon**, who remains with the company until year-end 2015.

Goodrich Petroleum Corp. hired **Joseph T. Leary** as its interim CFO.

TAG Oil Ltd.'s COO **Frank Jacobs** resigned to pursue other opportunities.

Seven Lakes Technologies appointed four executives to its senior leadership team: Chief Revenue Officer **Jim Schulte**, CFO **John Pitstick**, Chief Marketing Officer **Sowmya Murthy** and CTO **Bret Wiener**.

PDC Energy Inc.'s CFO **Gysle Shellum** will retire from the company June 30, 2016.

Tethys Petroleum Ltd.'s CFO **Denise Lay's** employment ended following the closure of the company's Guernsey office. Lay was offered to continue as CFO but chose not to relocate.

Matt Kirk joined Wood Group Kenny as vice president of operations in Houston.

Penn Virginia Corp.'s President and CEO **Baird Whitehead** retired in October. **Edward B. Cloues, II**, chairman of the board, will assume the additional role of interim CEO.

The Energy Industries Council selected **Chris Haynes** as its new president.

Ryan Bowley will serve as the Petroleum Equipment & Services Association's vice president of operations and external affairs.

Andrey Zakharov was elected director general of Gazprom Dobycha Krasnodar.

Chris Freeman joined io oil & gas consulting as director of field development. **Robert Dickson** was hired as director of field development project excellence. **Graham Inman** is the new operations director. Other hires include **Tim Highfield** as head of facilities, **Julio Herbas** as head of subsurface and **Philip Howe** as head of subsea.

Harkand appointed **Doug Fieldgate** Africa general manager.

Greene's Energy Group LLC named **Matt McIntosh** key account manager to be based in Houston.

Bill Maddock was named director of the Subsea Systems Institute.

Spirax Sarco selected **Shaun Lindley** as vice president of sales for the U.S.

Borets appointed **Nicholas P. Boyaci** business development manager to be based in Tulsa, Okla.

Coy Wilcox was named director for the Petroleum Extension, a component of the Texas Extended Campus at The University of Texas at Austin.

Energean Oil & Gas named **Dr. Medhat Tarakhan** country general manager in Egypt.

E-Finity added **Robert J. Pastorik Jr.** to its team to further grow the company's Capstone oil and gas business.

Emco Wheaton made two additions to the Americas sales team, with **Holly Damude** taking on the role of dry-break product specialist and **Eric Rodriguez** appointed as territory sales manager.

Petroplan appointed **James Monaghan** recruitment manager for its Houston office.

The 2015 to 2016 board members for The Lafayette Chapter of the American Association of Drilling Engineers are **Alden Sonnier**, **Matt Hensgens**, **Taylor Brazzel**, **Jarrod Suire**, **Sharon Moore**, **Al Wambsgans**, **Derrick Daigle**, **Lindsay Longman**, **Rick Voth**, **Jay Gallet**, **Rick Farmer**, **Jaime Crosby**, **Jeffery Svendson**, **Kristy Bonner**, **Joe Bernard**, **Tim Mannon**, **Sid Breaux**, **Bryce Percle**, **Bruce Jordan**, **Doug Keller** and **Andre Arceneaux.**

Marathon Oil Corp. selected **Gaurdie E. Banister Jr.** to join the company's board of directors.

Chesapeake Energy Corp. appointed **R. Brad Martin** nonexecutive chairman of the board of directors. As part of the transition, **Archie W. Dunham** will remain a director and has been named chairman emeritus.

Eurasia Drilling Co. Ltd. named **Murat Sampiev**, **Alexander Bogachev** and **Taleh Aleskerov** directors to fill current vacancies on the board.

Breitling Energy Corp. appointed **Cesar A. Baez** to the board of directors.

Advantek Waste Management Services LLC appointed **David Hayes** to its board of directors.

Greg Morris joined the board of directors as Spencer Ogden's global head of legal and compliance. **John Glover** joined the board as CFO.

Velocys Plc appointed **Mark Chatterji** nonexecutive director with immediate effect.

COMPANIES

INPEX Corp. opened its office in the Republic of Kazakhstan in Astana Oct. 1. Through this office INPEX will promote developing the giant offshore Kashagan oil field in the North Caspian Sea contract area.

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IMI Critical Engineering, in conjunction with Al Najim Saudi International, opened a new repair center in Jubail, Saudi Arabia, in September.

Simpson Gumpertz & Heger Inc. opened its Houston office, which will provide its full range of structural and building technology services, with a special emphasis on risk assessment and design associated with blast, seismic, hurricane and other hazards for the petroleum industry.

Warren Resources Inc.'s corporate headquarters relocated to its preexisting Denver office. The company will close its New York City and Roswell, N.M., offices.

Modal Training Ltd.'s new $10.8 million center of excellence for the ports, energy and logistics sectors is on schedule for completion and full operation in September 2016.

DSL MENA expands operation capability with a new facility in Hamriyah, United Arab Emirates, with quayside access providing direct access to the Arabian Gulf.

Maersk Training, together with Oiltec Solutions and eDrilling, was scheduled to open its new training facility in November 2015 in Houston. E&P

ADVERTISER INDEX

Collaboration is more than just a word

The industry needs to move past its reluctance to share.

Alistair Geddes, Expro

The recent SPE Offshore Europe conference and exhibition held in Aberdeen, U.K., once again provided an excellent platform to debate some of the critical issues affecting the industry at the moment, and key among those was the need for greater collaboration in the North Sea.

Two years ago few people in the oil and gas sector had cause to mention collaboration. Since then, Sir Ian Wood's "Maximising Economic Recovery Review," which made a clear call for greater collaboration between the industry, the U.K. Treasury and the new Oil and Gas Authority, has elevated it to buzzword status in certain quarters.

Yet while the need to collaborate was discussed at length in various gatherings at Offshore Europe, post-event the overriding concern was that while progress was being made in the U.K., it wasn't happening quickly enough.

This conclusion was enforced by a survey published by Deloitte just three weeks after Offshore Europe, indicating that a lack of effective supply chain collaboration meant companies were missing out on maximizing potential value from the U.K. Continental Shelf (UKCS).

> A report on the survey, which was conducted among 61 operators and oilfield service companies, revealed that while 74% of respondents believed collaboration was an integral part of their day-to-day business, only 27% of them said their efforts had resulted in a successful outcome.

A report on the survey, which was conducted among 61 operators and oilfield service companies, revealed that while 74% of respondents believed collaboration was an integral part of their day-to-day business, only 27% of them said their efforts had resulted in a successful outcome. Furthermore, only one in five said they actively sought out opportunities to collaborate.

These findings echoed comments I heard at Offshore Europe in my role as technical co-chair of "Developing Talent to Meet Demand." One person, experienced in many sectors but relatively new to oil and gas, said that he had never come across an industry less willing to share information than ours.

Despite the clear warnings for the North Sea from Sir Ian Wood, Oil & Gas UK and others, the industry seems reluctant to widely embrace collaboration. Why is this so?

From operators' perspectives, the motivation to collaborate, beyond an altruistic wish for the greater good of the North Sea, may be difficult to find.

They might feel that many of their business best practices, technologies and procedures, which they have taken time, effort and money to develop and create true cost reduction in a market that is highly sensitive to price, are the very items that give them a competitive advantage and they therefore might feel reluctant to share.

Inherent in the industry is a desire for companies to outperform each other, not least in terms of the financial returns generated. When operators are weighing the pros and cons of investment in the North Sea against potentially more attractive propositions elsewhere, how can we convince them that our region needs companies that will work together for the benefit of all?

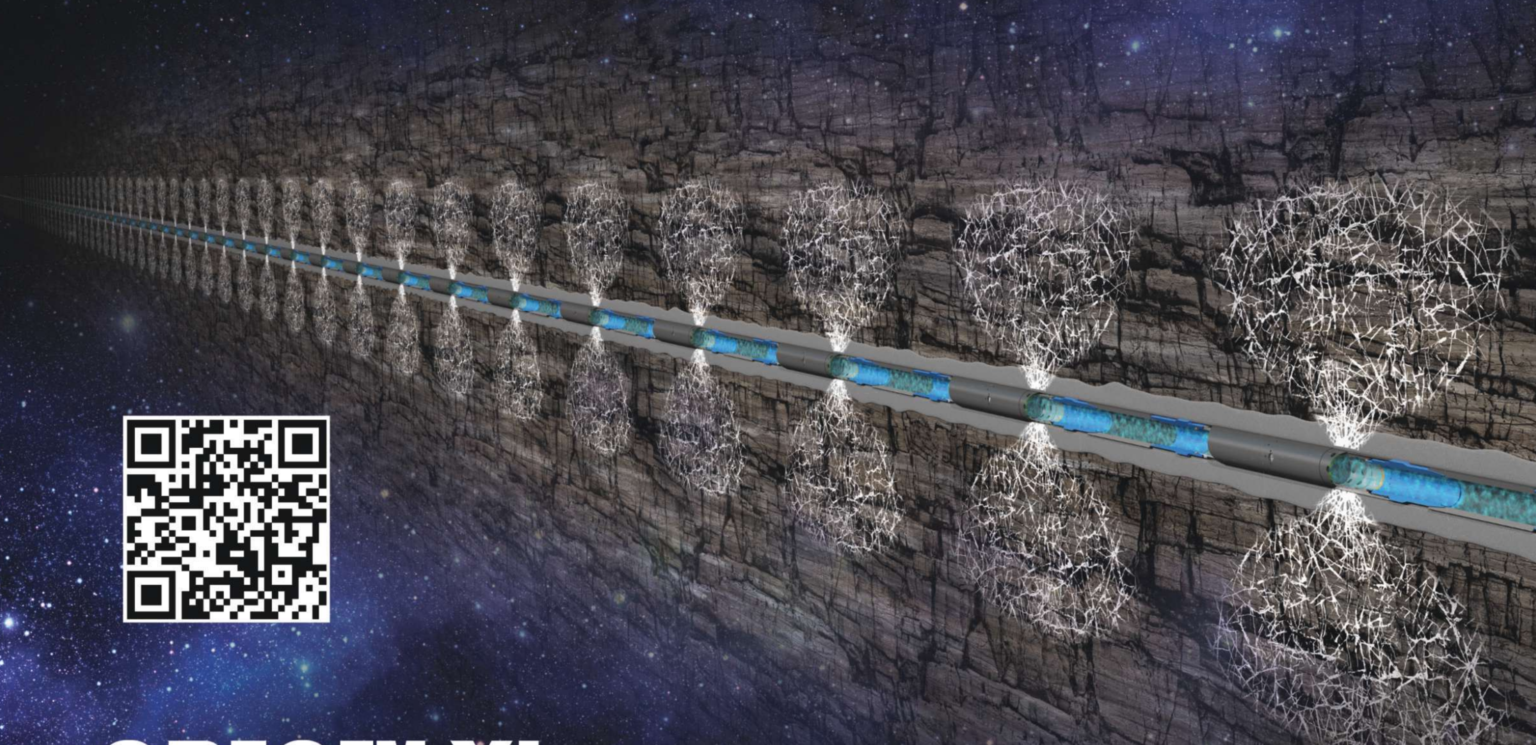
The culture of competition also pervades the service sector, where some of the smaller providers might fear being outflanked by larger rivals. However, dialogue between operators and service companies needs to improve, and increased standardization is recognized as one way that the service sector can make itself more cost-efficient.

From the Treasury, an index-linked tax system reacting to the actual state of the oil and gas industry would help avoid the current lag between the North Sea's fortunes and the demands of the public purse.

For Expro, commonsense collaboration is a principle the company has upheld for some time, particularly in working with other service providers through the delivery of multiservice crews, which can help optimize the footprint offshore.

There are many agencies working extremely hard to bring about the changes that are needed in the UKCS. With the shadow of decommissioning growing ever longer on our sunset sector, we must help them act on these changes quickly to ensure our survival.

Time is already against us. Let's not be against ourselves any longer. E&P



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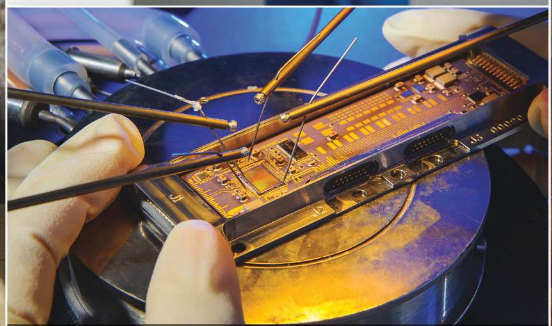

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